Duke Energy Arlington Valley, LLC
ARLINGTON VALLEY ENERGY FACILITY
Permit Number V99-014

These permit conditions incorporate the following Permit Revisions:
Minor Modification 9-06-01-01
Significant Revision S01-004

Table Of Contents
November 6, 2003

GENERAL PERMIT CONDITIONS:

SPECIFIC PERMIT CONDITIONS

APPENDICES:

Duke Energy Arlington Valley, LLC
ARLINGTON VALLEY ENERGY FACILITY
(AVEF I and AVEF II)
Permit Number V99-014

These permit conditions incorporate the following Permit Revisions:

Minor Modification 9-06-01-01
Significant Revision S01-004

November 6, 2003

In accordance with Maricopa County Air Pollution Control Rules and Regulations (Rules), Rule 210 § 302.2, all Conditions of this Permit are federally enforceable unless they are identified as being locally enforceable only. However, any Permit Condition identified as locally enforceable only will become federally enforceable if, during the term of this Permit, the underlying requirement becomes a requirement of the Clean Air Act (CAA) or any of the CAA's applicable requirements.

All federally enforceable terms and conditions of this Permit are enforceable by the Administrator of the United States Environmental Protection Agency (Administrator or Administrator of the USEPA hereafter) and citizens under the CAA.

Any cited regulatory paragraphs or section numbers refer to the version of the regulation that was in effect on the first date of public notice of the applicable Permit Condition unless specified otherwise.

GENERAL CONDITIONS:

1. **AIR POLLUTION PROHIBITED:** [County Rule 100 §301] [SIP Rule 3]
The Permittee shall not discharge from any source whatever into the atmosphere regulated air pollutants which exceed in quantity or concentration that specified and allowed in the County or State Implementation Plan (SIP) Rules, the Arizona Administrative Code (AAC) or the Arizona Revised Statutes (ARS), or which cause damage to property or unreasonably interfere with the comfortable enjoyment of life or property of a substantial part of a community, or obscure visibility, or which in any way degrade the quality of the ambient air below the standards established by the Maricopa County Board of Supervisors or the Director of the Arizona Department of Environmental Quality (ADEQ).

2. **CIRCUMVENTION:** [County Rule 100 §104] [40 CFR 60.12] [40 CFR 63.4(b)]
The Permittee shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of regulated air pollutants to the atmosphere, conceals or dilutes an emission which

would otherwise constitute a violation of this Permit or any Rule or any emission limitation or standard. The Permittee shall not circumvent the requirements concerning dilution of regulated air pollutants by using more emission openings than is considered normal practice by the industry or activity in question.

3. CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS:

[County Rule 100 §401] [County Rule 210 §§301.7, 302.1e(1), 305.1c(1) & 305.1e]

Any application form, report, or compliance certification submitted under the County Rules or these Permit Conditions shall contain certification by a responsible official of truth, accuracy, and completeness of the application form or report as of the time of submittal. This certification and any other certification required under the County Rules or these Permit Conditions shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

4. COMPLIANCE:

A. COMPLIANCE REQUIRED:

1) The Permittee must comply with all conditions of this permit and with all applicable requirements of Arizona air quality statutes and the air quality rules. Compliance with permit terms and conditions does not relieve, modify, or otherwise affect the Permittee's duty to comply with all applicable requirements of Arizona air quality statutes and the Maricopa County Air Pollution Control Regulations. Any permit non-compliance is grounds for enforcement action; for a permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application. Noncompliance with any federally enforceable requirement in this Permit constitutes a violation of the Act. [This Condition is federally enforceable if the condition or requirement itself is federally enforceable and only locally enforceable if the condition or requirement itself is locally enforceable only.]

[County Rule 210 §§301.8 b(4) & 302.1h(1)]

2) The Permittee shall halt or reduce the permitted activity in order to maintain compliance with applicable requirements of Federal laws, Arizona laws, the County Rules, or other conditions of this Permit.

[County Rule 210 §302.1h(2)]

3) For any major source operating in a nonattainment area for any pollutant(s) for which the source is classified as a major source, the source shall comply with reasonably available control technology (RACT) as defined in County Rule 100.

[County Rule 210 §302.1(h)(6)] [SIP Rule 220 §302.1]

Compliance with the RACT requirements of this Permit Condition for nitrogen oxides (NO_x) shall not be required if a waiver granted by the Administrator under Section 182 (f) of the Clean Air Act is in effect.

4) For any major source operating in a nonattainment area designated as serious for PM10, for which the source is classified as a major source for PM10, the source shall comply with the best available control technology (BACT), as defined in County Rule 100.

[County Rule 210 §302.1(h)(7)]

B. COMPLIANCE CERTIFICATION REQUIREMENTS:

[County Rule 210 §305.1d]

The Permittee shall file an annual compliance certification with the Control Officer and also with the Administrator of the USEPA. The report shall certify compliance with the terms and conditions contained in this Permit, including emission limitations, standards, or work practices. The certification shall be on a form supplied or approved by the Control Officer and shall include each of the following:

1) The identification of each term or condition of the permit that is the basis of the certification;
2) The compliance status;
3) Whether compliance was continuous or intermittent;
4) The method(s) used for determining the compliance status of the source, currently and over the reporting period; and
5) Other facts as the Control Officer may require to determine the compliance status of the source.

The annual certification shall be filed at the same time as the second semiannual monitoring report required by the Specific Condition section of these Permit Conditions and every 12 months thereafter.

C. COMPLIANCE PLAN: [County Rule 210 §305.1g]
Based on the certified information contained in the application for this Permit, the facility is in compliance with all applicable requirements in effect as of the release date of the proposed conditions for this Permit. The Permittee shall continue to comply with all applicable requirements and shall meet any applicable requirements that may become effective during the term of this permit on a timely basis. [This Condition is federally enforceable if the applicable requirement itself is federally enforceable and only locally enforceable if the applicable requirement itself is locally enforceable only.]

5. CONFIDENTIALITY CLAIMS: [County Rule 100 §402] [County Rule 200 §411]
Any records, reports or information obtained from the Permittee under the County Rules or this Permit shall be available to the public, unless the Permittee files a claim of confidentiality in accordance with ARS §49-487(c) which:

A. precisely identifies the information in the permit(s), records, or reports which is considered confidential, and
B. provides sufficient supporting information to allow the Control Officer to evaluate whether such information satisfies the requirements related to trade secrets or, if applicable, how the information, if disclosed, could cause substantial harm to the person's competitive position.
The claim of confidentiality is subject to the determination by the Control Officer as to whether the claim satisfies the claim for trade secrets.

A claim of confidentiality shall not excuse the Permittee from providing any and all information required or requested by the Control Officer and shall not be a defense for failure to provide such information.

If the Permittee submits information with an application under a claim of confidentiality under ARS 49-487 and County Rule 200, the Permittee shall submit a copy of such information directly to the Administrator of the USEPA.
[County Rule 210 §301.5]

6. CONTINGENT REQUIREMENTS:

NOTE: This Permit Condition covers activities and processes addressed by the CAA which may or may not be present at the facility. This condition is intended to meet the requirements of both Section 504(a) of the 1990 Amendments to the CAA, which requires that Title V permits contain conditions necessary to assure compliance with applicable requirements of the Act as well as the Acid Rain provisions required to be in all Title V permits.

A. ACID RAIN: [County Rule 210 §§302.1b(2) & 302.1f] [County Rule 371 §301]

1) Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the CAA and incorporated under County Rule 371, both provisions shall be incorporated into this Permit and shall be enforceable by the Administrator.

2) The Permittee shall not allow emissions exceeding any allowances that the source lawfully holds under Title IV of the CAA or the regulations promulgated thereunder and incorporated under County Rule 371.
   a) No permit revision shall be required for increases in emissions that are authorized by allowances acquired under the acid rain program and incorporated under County Rule 371, provided that such increases do not require a permit revision under any other applicable requirement.
   b) No limit is placed on the number of allowances held by the Permittee. The Permittee may not, however, use allowances as a defense to non-compliance with any other applicable requirement.
   c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the CAA.
   d) All of the following prohibitions apply to any unit subject to the provisions of Title IV of the CAA and incorporated into this Permit under County Rule 371:
      (1) Annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide held by the owners or operators of the unit or the designated representative of the owners or operators.
      (2) Exceedances of applicable emission rates.
      (3) The use of any allowance prior to the year for which it was allocated.
      (4) Violation of any other provision of the permit.

B. ASBESTOS:

[40 CFR 61, Subpart M] [County Rule 370 §301.8 - locally enforceable only]

The Permittee shall comply with the applicable requirements of Sections 61.145 through 61.147 and 61.150 of the National Emission Standard for Asbestos and County Rule 370 for all demolition and renovation projects.

C. RISK MANAGEMENT PLAN (RMP): [40 CFR 68]

Should this stationary source, as defined in 40 CFR 68.3, be subject to the accidental release prevention regulations in 40 CFR Part 68, then the Permittee shall submit an RMP by the date specified in 40 CFR Section 68.10 and shall certify compliance with the requirements of 40 CFR Part 68 as part of the annual compliance certification as required by 40 CFR Part 70. However, neither the RMP nor modifications to the RMP shall be considered to be a part of this Permit.

D. STRATOSPHERIC OZONE PROTECTION: [40 CFR 82 Subparts E, F, and G]

If applicable, the Permittee shall follow the requirements of 40 CFR 82.106 through 82.124 with respect to the labeling of products using ozone depleting substances.

If applicable, the Permittee shall comply with all of the following requirements with respect to recycling and emissions reductions:

1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices under 40 CFR 82.156.
2) Equipment used during maintenance, service, repair, or disposal of appliances must meet the standards for recycling and recovery equipment in accordance with 40 CFR 82.158.
3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by a certified technician under 40 CFR 82.161.

If applicable, the Permittee shall follow the requirements of 40 CFR Subpart G, including all Appendices, with respect to the safe alternatives policy on the acceptability of substitutes for ozone-depleting compounds.

7. **DUTY TO SUPPLEMENT OR CORRECT APPLICATION:** [County Rule 210 §301.6]
If the Permittee fails to submit any relevant facts or has submitted incorrect information in a permit application, the Permittee shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, the Permittee shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a proposed permit.

8. **EMERGENCY EPISODES:** [County Rule 600 §302] [SIP Rule 72.A.5. e, f & g]
If an air pollution alert, warning, or emergency has been declared, the Permittee shall comply with any applicable requirements of County Rule 600 §302.

9. **EMERGENCY PROVISIONS:** [County Rule 130 §§201 & 402]
An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, that requires immediate corrective action to restore normal operation, and that cause the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

An emergency constitutes an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the requirements of this Permit Condition are met.

The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

A. An emergency occurred and that the Permittee can identify the cause or causes of the emergency;
B. At the time of the emergency, the permitted source was being properly operated;
C. During the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in this permit; and

D. The Permittee as soon as possible telephoned the Control Officer giving notice of the emergency and submitted notice of the emergency to the Control Officer by certified mail, facsimile, or hand delivery within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirement of County Rule 210 §302.1.e(2) with respect to deviation reporting. This notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective action taken.

In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

This provision is in addition to any emergency or upset provision contained in any applicable requirement.

10. EXCESS EMISSIONS: [County Rule 140 §§401 & 402[[locally enforceable only]

NOTE: This Permit Condition is based on a County Rule which has not been adopted into the State Implementation Plan and is therefore applicable only at the County level.

There are reporting requirements associated with excess emissions. These requirements are contained in the Reporting section of the General Permit Conditions in a subparagraph called Excess Emissions. The definition of excess emissions can be found in County Rule 100 §200.

A. Affirmative Defense for Malfunctions: Emissions in excess of an applicable emission limitation due to malfunction shall constitute a violation. The owner and/or operator of a source with emissions in excess of an applicable emission limitation due to malfunction has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the owner and/or operator of the source has complied with the excess emissions reporting requirements of these Permit Conditions and has demonstrated all of the following:

1) The excess emissions resulted from a sudden and unavoidable breakdown of the process equipment or the air pollution control equipment beyond the reasonable control of the operator;
2) The source's air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;
3) If repairs were required, the repairs were made in an expeditious fashion when the applicable emission limitations were being exceeded. Off-shift labor and overtime were utilized where practicable to ensure that the repairs were made as expeditiously as possible. If off-shift labor and overtime were not utilized, then the owner and/or operator satisfactorily demonstrated that such measures were impractical;
4) The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;
5) All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;
6) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

7) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in County Rule 510 that could be attributed to the emitting source.
8) The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned, and could not have been avoided by better operations and maintenance practices;
9) All emissions monitoring systems were kept in operation, if at all practicable; and
10) The owner's and/or operator's actions in response to the excess emissions were documented by contemporaneous records.

B. Affirmative Defense For Startup And Shutdown:

1) Except as provided in paragraph 2) below, and unless otherwise provided for in the applicable requirement, emissions in excess of an applicable emission limitation due to startup and shutdown shall constitute a violation. The owner and/or operator of a source with emissions in excess of an applicable emission limitation due to startup and shutdown has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the owner and/or operator of the source has complied with the excess emissions reporting requirements of these Permit Conditions and has demonstrated all of the following:
   a. The excess emissions could not have been prevented through careful and prudent planning and design;
   b. If the excess emissions were the result of a bypass of control equipment, the bypass was unavoidable to prevent loss of life, personal injury, or severe damage to air pollution control equipment, production equipment, or other property;
   c. The source's air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;
   d. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable, during periods of such emissions;
   e. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;
   f. During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in County Rule 510 (Air Quality Standards) that could be attributed to the emitting source;
   g. All emissions monitoring systems were kept in operation, if at all practicable; and
   h. The owner's and/or operator's actions in response to the excess emissions were documented by contemporaneous records.

2) If excess emissions occur due to a malfunction during routine startup and shutdown, then those instances shall be treated as other malfunctions subject to paragraph A. of this Permit Condition.

C. Affirmative Defense For Malfunctions During Scheduled Maintenance: If excess emissions occur due to malfunction during scheduled maintenance, then those instances will be treated as other malfunctions subject to paragraph A. of this Permit Condition.

D. Demonstration of Reasonable And Practicable Measures: For an affirmative defense under paragraphs A and B of this Permit Condition, the owner and/or operator of the source shall demonstrate, through submission of the data and information required by this Permit Condition and the excess emissions reporting requirements of these Permit Conditions that all reasonable and practicable measures within the owner's and/or operator's control were implemented to prevent the occurrence of the excess emissions.

11. FEES: [County Rule 200 §409] [County Rule 210 §§302.1i & §401]
The Permittee shall pay fees to the Control Officer under ARS 49-480(D) and County Rule 280.

12. MODELING: [County Rule 200 §407] [locally enforceable only]
Where the Control Officer requires the Permittee to perform air quality impact modeling, the Permittee shall perform the modeling in a manner consistent with the "Guideline on Air Quality Models (Revised)" (EPA-450/2-78-027R, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. 27711, July 1986) and "Supplement B to the Guideline on Air Quality Models" (U.S. Environmental Protection Agency, September 1990). Both documents shall be referred to hereinafter as "Guideline", and are adopted by reference. Where the person can demonstrate that an air quality impact model specified in the guideline is inappropriate, the model may be modified or another model substituted if found to be acceptable to the Control Officer.

13. MONITORING / TESTING:

A. The Permittee shall monitor, sample, or perform other studies to quantify emissions of regulated air pollutants or levels of air pollution that may reasonably be attributable to the facility if required to do so by the Control Officer, either by Permit or by order in accordance with County Rule 200 §309.
[County Rule 200 §309] [SIP Rule 41]

B. Except as otherwise specified in these Permit Conditions or by the Control Officer, the Permittee shall conduct required testing used to determine compliance with standards or permit conditions established under the County or SIP Rules or these Permit Conditions in accordance with County Rule 270 and the applicable testing procedures contained in the applicable, Rule, the Arizona Testing Manual for Air Pollutant Emissions or other approved USEPA test methods.
[County Rule 200 §408] [County Rule 210 §302.1.c] [County Rule 270 §§300 &400] [SIP Rule 27]

C. The Permittee may use equivalent test methods and procedures in lieu of those described in this paragraph if approved by the Control Officer.
[County Rule 270 §402]

D. The owner or operator of a permitted source shall provide, or cause to be provided, performance testing facilities as follows:
1) Sampling ports adequate for test methods applicable to such source.
2) Safe sampling platform(s).
3) Safe access to sampling platforms(s).
4) Utilities for sampling and testing equipment.

[County Rule 270 §405] [SIP Rule 42]

14. PERMITS:

A. BASIC: [County Rule 210 §302.1h(3)]

This Permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit revision, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any Permit Condition.

B. DUST CONTROL PLAN REQUIREMENTS:

1) The following describe the permit applications with which a Dust Control Plan must be submitted. *(NOTE: If the Permittee engages in or allows any routine dust generating activities at the facility, the Permittee shall apply to have the routine dust generating activity covered as part of this Permit. Nonroutine activities, such as construction and revegetation, require a separate Earthmoving Permit that must be obtained from the Control Officer before the activity may begin.)*

   a) If the Permittee is required to obtain an Earthmoving Permit under Regulation II (Permits And Fees) of the County Rules, then the Permittee must first submit a Dust Control Plan and obtain the Control Officer's approval of the Dust Control Plan before commencing any dust generating operation.

   b) The Permittee must first submit a Dust Control Plan and obtain the Control Officer's approval of the Dust Control Plan before commencing any routine dust generating operation.

[County Rule 310 §303.3] [SIP Rule 310 §303.3]

2) A Dust Control Plan shall not be required to play on a ballfield and/or for landscape maintenance. For the purpose of this Permit Condition, landscape maintenance does not include grading, trenching, nor any other mechanized surface disturbing activities.

[County Rule 200 §305] [County Rule 310 §303.4] [SIP Rule 310 §303.4]

3) Any Dust Control Plan shall, at a minimum, contain all the information described in Section 304 of Rule 310.

[County Rule 310 §304] [SIP Rule 310 §304]

4) Compliance with this section does not effect a source's responsibility to comply with the other standards of Rule 310 and these Permit Conditions. Failure to comply with the provisions of an approved Dust Control Plan or the work practice standards contained in Rule 310 §308 is deemed to be a violation of this Permit. Regardless of whether an approved Dust Control Plan is in place or not, the Permittee is still subject to all requirements of Rule 310 at all times. In addition, if the Permittee has an approved Dust Control Plan, the Permittee is still subject to all of the requirements of Rule 310, even if the Permittee is complying with the approved Dust Control Plan.

[County Rule 310 §303] [SIP Rule 310 §303]

5) The Permittee shall make revisions to any required Dust Control Plan when notified in writing by the Control Officer that implementation of the existing dust control plan allowed an exceedance of the standards established in Rule 310 §§301 or 302. The revised Dust Control Plan shall be submitted to the Control Officer within 3 working days of receiving the notice. During the time when the

Dust Control Plan is being revised, the Permittee must still comply with the requirements of this Permit and Rule 310.

[County Rule 310 §305] [SIP Rule 310 §305]

C. PERMITS AND PERMIT CHANGES, AMENDMENTS AND REVISIONS:

[County Rule 200 §§301 & 308]
[County Rule 210 §§301.4a, b, c, & 400]

1) The Permittee shall comply with the Administrative Requirements of Section 400 of County Rule 210 for all changes, amendments and revisions at the facility for any source subject to regulation under County Rule 200, shall comply with all required time frames, and shall obtain any required preapproval from the Control Officer before making changes. All applications shall be filed in the manner and form prescribed by the Control Officer. The application shall contain all the information necessary to enable the Control Officer to make the determination to grant or to deny a permit or permit revision including information listed in County Rule 200 §308 and County Rule 210 §§301 & 302.3.

2) The Permittee shall supply a complete copy of each application for a permit, a minor permit revision, or a significant permit revision directly to the Administrator of the USEPA. The Control Officer may require the application information to be submitted in a computer-readable format compatible with the Administrator's national database management system.

[County Rule 210 §§303.1a, 303.2, 405.4, & 406.4]

3) While processing an application, the Control Officer may require the applicant to provide additional information and may set a reasonable deadline for a response.

[County Rule 210 §301.4.f]

4) No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.

[County Rule 210 §302.1j]

D. POSTING:

1) The Permittee shall keep a complete permit clearly visible and accessible on the site where the equipment is installed.

[County Rule 200 §311] [SIP Rule 22F]

2) If a Dust Control Plan, as required by Rule 310, has been approved by the Control Officer, the Permittee shall post a copy of the approved Dust Control Plan in a conspicuous location at the work site, within on-site equipment, or in an on-site vehicle, or shall otherwise keep a copy of the Dust Control Plan available on site at all times.

[County Rule 310 §401] [SIP Rule 310 §401]

E. PROHIBITION ON PERMIT MODIFICATION: [County Rule 200 §310]

The Permittee shall not willfully deface, alter, forge, counterfeit, or falsify this permit.

F. RENEWAL:

1) The Permittee shall submit an application for the renewal of this Permit in a timely and complete manner. For purposes of permit renewal, a timely application is one that is submitted at least six months, but not more than 18 months, prior to the date of permit expiration. A complete application shall contain all of the information required by the County Rules including Rule 200 §308 and Rule 210 §§301 & 302.3.

[County Rule 210 §§301.2a, 301.4a, b, c, d, h & 302.3]

2) The Permittee shall file all permit applications in the manner and form prescribed by the Control Officer. To apply for a permit renewal, the Permittee shall complete the "Standard Permit Application Form" and shall supply all information, including the information required by the "Filing Instructions" as shown in Appendix B of the County Rules, which is necessary to enable the Control Officer to make the determination to grant or to deny a permit which shall contain such terms and conditions as the Control Officer deems necessary to assure a source's compliance with the requirements of the CAA, ARS and County Rules.

[County Rule 200 §§308 & 309] [County Rule 210 §301.1]

3) The Control Officer may require the Permittee to provide additional information and may set a reasonable deadline for a response.

[County Rule 210 §301.4f]

4) If the Permittee submits a timely and complete application for a permit renewal, but the Control Officer has failed to issue or deny the renewal permit before the end of the term of the previous permit, then the permit shall not expire until the renewal permit has been issued or denied. This protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit, by the deadline specified by the Control Officer, any additional information identified as being needed to process the application.

[County Rule 200 §403.2] [County Rule 210 §§301.4f & 301.9]

G. REVISION / REOPENING / REVOCATION:

1) This permit shall be reopened and revised to incorporate additional applicable requirements adopted by the Administrator pursuant to the CAA that become applicable to the facility if this permit has a remaining permit term of three or more years. No such reopening is required if the effective date of the requirement is later than the date on which this Permit is due to expire unless the original permit or any of its terms have been extended pursuant to Rule 200 §403.2.

[County Rule 200 §402.1]

Any permit revision required under this Permit Condition, 14.G.1, shall reopen the entire permit and shall comply with provisions in County Rule 200 for permit renewal *(Note: this includes a facility wide application and public comment on the entire permit)* and shall reset the five year permit term.

[County Rules 200 §402.1a(1) & 210 §302.5]

2) This permit shall be reopened and revised under any of the following circumstances:
   a. Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the Title V permit.
   b. The Control Officer or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.
   c. The Control Officer or the Administrator determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

   Proceedings to reopen and issue a permit under this Permit Condition, 14.G.2, shall follow the same procedures as apply to initial permit issuance and shall effect only those parts of the Permit for which cause to reopen exists.

   [County Rule 200 §402.1]

3) This permit shall be reopened by the Control Officer and any permit shield revised, when it is determined that standards or conditions in the permit are based on incorrect information provided by the applicant.

   [County Rule 210 §407.3]

4) This Permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Permit revision, revocation and reissuance, or termination or of a notification of planned changes or anticipated noncompliance does not stay any Permit Condition.

   [County Rule 210 §302.1h(3)]

H. REVISION UNDER A FEDERAL HAZARDOUS AIR POLLUTANT STANDARD:

[County Rule 210 §301.2c] [locally enforceable only]

If the Permittee becomes subject to a standard promulgated by the Administrator under Section 112(d) of the CAA, the Permittee shall, within 12 months of the date on which the standard is promulgated, submit an application for a permit revision demonstrating how the source will comply with the standard.

I. REQUIREMENTS FOR A PERMIT:

1) Air Quality Permit: Except as noted under the provisions in Sections 403 and 405 of County Rule 210, no source may operate after the time that it is required to submit a timely and complete application, except in compliance with a permit issued under County Rule 210. Permit expiration terminates the Permittee’s right to operate. However, if a source submits a timely and complete application, as defined in County Rule 210 §301, for permit issuance, revision, or renewal, the source's failure to have a permit is not a violation of the County Rules until the Control Officer takes final action on the application. The Source’s ability to operate without a permit as set forth in this paragraph shall be in effect from the date the application is determined to be complete until the final permit is issued. This protection shall cease to apply if, subsequent to the completeness determination, the applicant fails to submit, by the deadline specified in writing by the Control Officer, any additional information identified as being needed to process the application. If a source submits a timely and complete application

for a permit renewal, but the Control Officer has failed to issue or deny the renewal permit before the end of the term of the previous permit, then the permit shall not expire until the permit renewal has been issued or denied.

[County Rule 210 §301.9]

2) Earthmoving Permit:

(NOTE: If the Permittee engages in or allows any routine dust generating activities at the facility, the Permittee shall apply to have the routine dust generating activity covered as part of this Permit. Nonroutine activities, such as construction and revegetation, require a separate Earthmoving Permit that must be obtained from the Control Officer before the activity may begin.)

No person shall commence any earth moving operation or any dust generating operation without meeting the requirements of and obtaining any and all Earth Moving Equipment Permits and Permits to Operate required by County Rule 200. The provisions of this section shall not apply:

a) During emergency, life threatening situations or in conjunction with any officially declared disaster or state of emergency;
b) To operations conducted by essential service utilities to provide electricity, natural gas, oil and gas transmission, cable television, telephone, water, and sewerage during service outages and emergency disruptions;
c) To non-routine or emergency maintenance of flood control channels and water retention basins.
d) To vehicle test and development facilities and operations when dust is required to test and validate design integrity, product quality and/or commercial acceptance. Such facilities and operations shall be exempted from the provisions of this section only if such testing is not feasible within enclosed facilities.

[County Rule 310 §302] [SIP Rule 310 §302]

The Permittee shall not cause, commence, suffer, allow, or engage in any earthmoving operation that disturbs a total surface area of 0.10 acre or more without first obtaining a permit from the Control Officer. Permits shall not be required for earthmoving operations for emergency repair of utilities, paved roads, unpaved roads, shoulders, and/or alleys.

[County Rule 200 §305]

3) Burn Permit: The Permittee shall obtain a Permit To Burn from the Control Officer before conducting any open outdoor fire except for the activities listed in County Rule 314 §§302.1 and 302.2.

[County Rule 314] [County Rule 200 §306] [SIP Rule 314]

J. RIGHTS AND PRIVILEGES: [County Rule 210 §302.1h(4)]

This Permit does not convey any property rights nor exclusive privilege of any sort.

K. SEVERABILITY: [County Rule 210 §302.1g]

The provisions of this Permit are severable, and, if any provision of this Permit is held invalid, the remainder of this Permit shall not be affected thereby.

L. SCOPE:

The issuance of any permit or permit revision shall not relieve the Permittee from compliance with any Federal laws, Arizona laws, or the County or SIP Rules, nor does any other law, regulation or permit relieve the Permittee from obtaining a permit or permit revision required under the County Rules.

[County Rule 200 §308] [SIP Rule 22H]

Nothing in this permit shall alter or affect the following:

1) The provisions of Section 303 of the Act (Emergency Orders), including the authority of the Administrator of the USEPA under that section.
2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance.
3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Act.
4) The ability of the Administrator of the USEPA or of the Control Officer to obtain information from the Permittee under Section 114 of the Act, or any provision of State law.
5) The authority of the Control Officer to require compliance with new applicable requirements adopted after the permit is issued. [locally enforceable only]

[County Rule 210 §407.2]

M. TERM OF PERMIT: [County Rule 210 §§302.1a & 402]

This Permit shall remain in effect for no more than 5 years from the date of issuance.

N. TRANSFER: [County Rule 200 §404]

Except as provided in ARS 49-429 and County Rule 200, this permit may be transferred to another person if the Permittee gives notice to the Control Officer in writing at least 30 days before the proposed transfer and complies with the permit transfer requirements of County Rule 200 and the administrative permit amendment procedures under County Rule 210.

15. RECORDKEEPING:

A. RECORDS REQUIRED:

[County Rule 100 §501] [County Rule 310 §502] [SIP Rule 40 A]

The Permittee shall maintain records of all emissions testing and monitoring, records detailing all malfunctions which may cause any applicable emission limitation to be exceeded, records detailing the implementation of approved control plans and compliance schedules, records required as a condition of any permit, records of materials used or produced and any other records relating to the emission of air contaminants which may be requested by the Control Officer.

B. RETENTION OF RECORDS:

Unless a longer time frame is specified by these Permit Conditions, information and records required by applicable requirements and copies of summarizing reports recorded by the Permittee and submitted to the Control Officer shall be retained by the Permittee for 5 years after the date on which the information is recorded or the report is submitted.

[County Rule 100 §504] [SIP Rule 40 C]

The Permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

[County Rule 210 §§302.1 d (2)]

C. MONITORING RECORDS: [County Rule 210 §§302.1d(1) & 305.1b(1)]
Records of any monitoring required by this Permit shall include the following:

1) The date, place as defined in the permit, and time of sampling or measurements;
2) The date(s) analyses were performed;
3) The name of the company or entity that performed the analysis;
4) The analytical techniques or methods used;
5) The results of such analysis; and
6) The operating conditions as existing at the time of sampling or measurement

D. RIGHT OF INSPECTION OF RECORDS: [County Rule 100 §106] [SIP Rule 40 D]
When the Control Officer has reasonable cause to believe that the Permittee has violated or is in violation of any provision of County Rule 100 or any County Rule adopted under County Rule 100, or any requirement of this permit, the Control Officer may request, in writing, that the Permittee produce all existing books, records, and other documents evidencing tests, inspections, or studies which may reasonably relate to compliance or noncompliance with County Rules adopted under County Rule 100. No person shall fail nor refuse to produce all existing documents required in such written request by the Control Officer.

16. REPORTING:

NOTE: See the Permit Condition titled Certification Of Truth, Accuracy and Completeness in conjunction with reporting requirements.

A. ANNUAL EMISSION INVENTORY REPORT:
[County Rule 100 §505][SIP Rule 40 B]
Upon request of the Control Officer and as directed by the Control Officer, the Permittee shall complete and shall submit to the Control Officer an annual emissions inventory report. The report is due by April 30 or 90 days after the Control Officer makes the inventory form(s) available, whichever occurs later.

The annual emissions inventory report shall be in the format provided by the Control Officer.

The Control Officer may require submittal of supplemental emissions inventory information forms for air contaminants under ARS §49-476.01, ARS §49-480.03 and ARS §49-480.04.

B. DATA REPORTING: [County Rule 100 §502]
When requested by the Control Officer, the Permittee shall furnish to the Maricopa County Air Quality Division (Division hereafter) information to locate and classify air contaminant sources according to type, level, duration, frequency and other

characteristics of emissions and such other information as may be necessary. This information shall be sufficient to evaluate the effect on air quality and compliance with the County or SIP Rules. The Permittee may subsequently be required to submit annually, or at such intervals specified by the Control Officer, reports detailing any changes in the nature of the source since the previous report and the total annual quantities of materials used or air contaminants emitted.

C. DEVIATION REPORTING:

[County Rule 210 §§302.1e & 305.1c]

The Permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions. Unless specified otherwise elsewhere in these Permit Conditions, an upset for the purposes of this Permit Condition shall be defined as the operation of any process, equipment or air pollution control device outside of either its normal design criteria or operating conditions specified in this Permit and which results in an exceedance of any applicable emission limitation or standard. The Permittee shall submit the report to the Control Officer by certified mail, facsimile, or hand delivery within 2 working days from knowledge of the deviation. The report shall contain a description of the probable cause of such deviations and any corrective actions or preventive measures taken. In addition, the Permittee shall report within a reasonable time of any long-term corrective actions or preventative actions taken as the result of any deviations from permit requirements.

All instances of deviations from the requirements of this Permit shall also be clearly identified in the semiannual monitoring reports required in the Specific Condition section of these Permit Conditions.

D. EMERGENCY REPORTING: [County Rule 130 §402.4]

(NOTE: Emergency Reporting is one of the special requirements which must be met by a Permittee wishing to claim an affirmative defense under the emergency provisions of County Rule 130. These provisions are listed earlier in these General Conditions in the section titled "Emergency Provisions". Since it is a form of deviation reporting, the filing of an emergency report also satisfies the requirement of County Rule 210 to file a deviation report.)

The Permittee shall, as soon as possible, telephone the Control Officer giving notice of the emergency and submitted notice of the emergency to the Control Officer by certified mail, facsimile, or hand delivery within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective action taken.

E. EMISSION STATEMENTS REQUIRED AS STATED IN THE ACT:

[County Rule 100 §503]

Upon request of the Control Officer and as directed by the Control Officer, the Permittee shall provide the Control Officer with an emission statement, in such form as the Control Officer prescribes, showing measured actual emissions or estimated actual emissions of NO_x and volatile organic compounds (VOC) from that source. At a minimum the emission statement shall contain all information contained in the "Guidance on Emission Statements" document as described in the USEPA's Aerometric Information Retrieval System (AIRS) Fixed Format Report (AFP 644). The statement shall contain emissions for the time period specified by the Control Officer. Statements shall be submitted annually.

F. EXCESS EMISSIONS REPORTING:

[County Rule 140 §§500] [locally enforceable only]

(NOTE: This reporting subsection is associated with the requirements listed earlier in these General Conditions in the section titled "Excess Emissions".)

1) The owner and/or operator of any source shall report to the Control Officer any emissions in excess of the limits established by the County or SIP Rules or by these Permit Conditions. The report shall be in two parts as specified below:
   (a) Notification by telephone or facsimile within 24 hours of the time when the owner and/or operator first learned of the occurrence of excess emissions that includes all available information from paragraph 2) of this Permit Condition.
   (b) Detailed written notification by submission of excess emissions report within 72 hours of the notification required by paragraph 1) a) of this Permit Condition.
b) The excess emissions report shall contain the following information:
   (a) The identity of each stack or other emission point where the excess emissions occurred;
   (b) The magnitude of the excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions;
   (c) The time and duration or expected duration of the excess emissions;
   (d) The identity of the equipment from which the excess emissions emanated;
   (e) The nature and cause of such emissions;
   (f) The steps taken if the excess emissions were the result of a malfunction to remedy the malfunction and the steps taken or planned to prevent the recurrence of such malfunctions;
   (g) The steps that were or are being taken to limit the excess emissions; and
   (h) If this Permit contains procedures governing source operation during periods of startup or malfunction and the excess emissions resulted from startup or malfunction, a list of the steps taken to comply with the Permit procedures.

3) In the case of continuous or recurring excess emissions, the notification requirements of this Permit Condition shall be satisfied if the source provides the required notification after excess emissions are first detected and includes in the notification an estimate of the time the excess emissions will continue. Excess emissions occurring after the estimated time period or changes in the nature of the emissions as originally reported shall require additional notification pursuant to paragraphs 1) and 2) of this Permit Condition.

G. OTHER REPORTING: [County Rule 210 §302.1h(5)]

The Permittee shall furnish to the Control Officer, within a reasonable time, any information that the Control Officer may request in writing to determine whether cause exists for revising, revoking and reissuing this permit, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to the Control Officer copies of records required to be kept by this Permit. For information claimed to be confidential, the Permittee shall furnish a copy of such records directly to the Administrator of the USEPA along with a claim of confidentiality as covered elsewhere in these Permit Conditions.

17. RIGHT TO ENTRY AND INSPECTION OF PREMISES:

[County Rule 100 §105] [County Rule 210 §305.1f] [SIP Rule 43]

The Control Officer during reasonable hours, for the purpose of enforcing and administering County Rules, or any provision of ARS relating to the emission or control prescribed pursuant thereto, may enter every building, premises, or other place, except the interior of structures used as private residences. Every person is guilty of a petty offense under ARS §49-488 who in any way denies, obstructs or hampers such entrance or inspection that is lawfully authorized by warrant.

The Permittee shall allow the Control Officer or his authorized representative, upon presentation of proper credentials and other documents as may be required by law, to:

A. Enter upon the Permittee's premises where a source is located or emissions-related activity is conducted, or where records are required to be kept under the conditions of the permit;
B. Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of the permit;
C. Inspect, at reasonable times, any sources, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;
D. Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements; and
E. To record any inspection by use of written, electronic, magnetic, and photographic media.

[Locally enforceable only]

SPECIFIC CONDITIONS:

18. ALLOWABLE EMISSION LIMITATIONS

The allowable emission limits of these Permit Conditions are based upon the facility as currently permitted. They do not provide for facility changes or changes in the method of operation that would otherwise trigger applicable requirements including New Source Review, Prevention of Significant Deterioration or Best Available Control Technology.

A. Facility - Wide Requirements:

1) Facility Equipment

The major emitting equipment to be constructed at the facility is described in Appendix A. The Permittee shall not deviate from the equipment described in Appendix A.

[County Rule 240, §301]

2) Facility Emission Limits

In addition to emission limits expressed elsewhere in this Permit, the Permittee shall not cause, allow, or permit emissions to exceed the hourly and rolling total limits shown in Tables 1 through 13. *[Refer to the Notes located after Table 13 at the end of this subsection and Appendix A for explanation of terms.]*

Table 1
Facility Wide Rolling 12-month Total Emission Limits (AVEF I and AVEF II) with AVEF I and AVEF II based on BACT

Note: In addition to the facility total emission limits contained in this Table 1, AVEF I and AVEF II have individual emission limits as shown in the following tables and permit conditions. Furthermore, AVEF II has a dual set of emission limits, one set that is voluntarily accepted and equivalent to lowest achievable emission rates, and one set that is federally enforceable based on BACT. This Table 1 is based on BACT for AVEF I and AVEF II.

	Rolling 12-month Total Emission Limits (tons per year)					
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**	**Hazardous Air Pollutants (HAPs)**
Total of four Combined Cycle Systems for AVEF I and AVEF II	93.0	444.6 Note (r)	1,416.6	407.8	242.6	NS
Total of two Auxiliary Boilers for AVEF I and	0.4	6.6	28.2	1.8	3.0	NS

AVEF II						
Total of two Cooling Towers for AVEF I and AVEF II	NA	NA	NA	19.0	NA	NS
Total of All Emitting Devices at AVEF I and II	93.4	451.2 Note (r)	1,444.8	428.6	245.6	9.0 any individual HAP, 22.5 aggregate of all HAPs

Table 2
Facility Wide Rolling 12-month Total Locally Enforceable Emission Limits (AVEF I and AVEF II)

Note: In addition to the facility total emission limits contained in this Table 2, AVEF I and AVEF II have individual emission limits as shown in the following tables and permit conditions. Furthermore, AVEF II has a dual set of emission limits, one set that is voluntarily accepted, locally enforceable levels, and one set that is federally enforceable based on BACT. This Table 2 is based on the voluntarily accepted, locally enforceable levels.

	Rolling 12-month Total Emission Limits (tons per year)					
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**	**Hazardous Air Pollutants (HAPs)**
Total of four Combined Cycle Systems for AVEF I and AVEF II	93.0	444.6 Note (r)	1,375.0	358.0	195.0	NS
Total of two Auxiliary Boilers for AVEF I and AVEF II	0.4	6.6	28.2	1.8	3.0	NS
Total of two Cooling Towers for AVEF I and AVEF II	NA	NA	NA	19.0	NA	NS
Total of All Emitting Devices at AVEF I and II	93.4	451.2 Note (r)	1,403.2	378.8	198.0	9.0 any individual HAP, 22.5 aggregate of all HAPs

Table 3
AVEF I Rolling 12-month Total Emission Limits (tons per year)

Device	SO_2	NO_x	CO	PM_{10}	VOC
Combined Cycle System #1	19.8	121.1 Note (r)	438.1	99.9	61.6
Combined Cycle System #2	19.8	121.1 Note (r)	438.1	99.9	61.6
Auxiliary Boiler	0.2	3.3	14.1	0.9	1.5
Cooling Tower	NA	NA	NA	18.2	NA

[County Rule 240, §308.1(a), (d), (e)]

Table 4
Hourly Emission Limits During Periods When an AVEF I Combined Cycle System Operates in Conditions Other than Startup or Shutdown (lb/hr)

Device	SO_2	NO_x	CO	PM_{10}	VOC
Combustion Turbine #1, Duct Burners OFF	4.00	20.2 Note (r)	34.0	20.0	3.0
Combustion Turbine #1, Duct Burners ON	5.25	24.0 Note (r)	62.0	24.0	12.8
Combustion Turbine #2, Duct Burners OFF	4.00	20.2 Note (r)	34.0	20.0	3.0
Combustion Turbine #2, Duct Burners ON	5.25	24.0 Note (r)	62.0	24.0	12.8

[County Rule 240, §308.1(a), (d), (e)][40 CFR 60.43a(b), (g)][40 CFR 60.333(a)]
[County Rule 360 §301]

Table 5
Emission Limits for the AVEF I Combined Cycle Systems During Periods of Startup or Shutdown (lb/event)

Device	NO_x	CO	VOC
Combustion Turbine #1 and #2 Combined during Startup	799.0	2,484.0 (Note 1)	142.0
Combustion Turbine #1 and #2 combined during Shutdown	124.0	712.0	44.0

Note 1: There is also a maximum pounds per hour limit of 2,520 lb/hr CO.

[County Rule 240, §308.1(a), (d), (e)]

Table 6
Hourly Emission Limits for the Auxiliary Boiler (lb/hr)

Device	SO_2	NO_x	CO	PM_{10}	VOC
Auxiliary Boiler	0.08	3.11	4.95	0.33	0.53

[County Rule 240, §308.1(a), (d), (e)]

Table 7
Additional Concentration or Rate Emission Limits for AVEF I

Device	NO_x	CO	PM_{10} Solids (Filterable) Alone	PM_{10} Total (Filterable plus Condensable)	VOC	Other
Each Combustion Turbine #1 or #2 Exhaust when Operating in Conditions Other than Startup or Shutdown	NS	NS	9 lbs/hr	24.0 lbs/hr	NS	NS
Each Duct Burner Set #1 or #2 Exhaust	NS	NS	0.03 lb/mmBtu	NS	NS	NS
Each Combined Cycle System #1 or #2 Exhaust	3 ppm 3-hour rolling average Note (r) **NSPS:** 1.6 lb/MW-hrs	20 ppm with Duct Burners ON and 10 ppm with Duct Burners OFF, 3-hour rolling average	NS	NS	4.8 ppm with Duct Burners ON and 1.4 ppm with Duct Burners OFF, 3-hour average	**Ammonia** 10 ppm 24-hour rolling average
Auxiliary Boiler Exhaust	0.035 lb/mmBtu	0.150 lb/mmBtu				No more than 6,000 hours operation per rolling 12-month period

[County Rule 240, §308.1(a), (d), (e)] [40 CFR 60.42a(a)(1)] [40 CFR 60.44a(d)(1)]
[40 CFR 60.332(a)(1)] [County Rule 360 §301] [40 CFR 60.46a(c)]

Table 8
AVEF II Rolling 12-month Total Federally Enforceable Limits at BACT (tons per year)

Device	SO_2	NO_x	CO	PM_{10}	VOC
Combined Cycle System #3	26.7	101.2 Note (r)	270.2	104.0	59.7
Combined Cycle System #4	26.7	101.2 Note (r)	270.2	104.0	59.7
Auxiliary Boiler	0.2	3.3	14.1	0.9	1.5
Cooling Tower	NA	NA	NA	7.5	NA

[County Rule 240, §308.1(a), (d), (e)]

Table 9
AVEF II Rolling 12-month Total Locally Enforceable Limits (LEL) (tons per year)
[locally enforceable only]

Device	SO_2	NO_x	CO	PM_{10}	VOC
Combined Cycle System #3	26.7	101.2	249.4	79.1	35.9
Combined Cycle System #4	26.7	101.2	249.4	79.1	35.9
Auxiliary Boiler	0.2	3.3	14.1	0.9	1.5
Cooling Tower	NA	NA	NA	7.5	NA

[County Rule 240, §308.1(a), (d), (e)]

Table 10
Hourly Emission Limits During Periods When an AVEF II Combined Cycle System Operates in Conditions Other than Startup or Shutdown (lb/hr)
[LEL limits are locally enforceable only]

Device	SO_2	NO_x	CO	PM_{10}	VOC
Combustion Turbine #3, Duct Burners OFF	BACT 5.0 LEL 5.0	BACT 13.4 Note (r) LEL 13.4	BACT 8.2 LEL 8.2	BACT 18.0 LEL 15.0	BACT 2.3 LEL 2.3
Combustion Turbine #3, Duct Burners ON	BACT 6.5 LEL 6.5	BACT 18.4 Note (r) LEL 18.4	BACT 16.8 LEL 11.2	BACT 25.0 LEL 19.0	BACT 12.8 LEL 6.4
Combustion Turbine #4, Duct Burners OFF	BACT 5.0 LEL 5.0	BACT 13.4 Note (r) LEL 13.4	BACT 8.2 LEL 8.2	BACT 18.0 LEL 15.0	BACT 2.3 LEL 2.3
Combustion Turbine #4, Duct Burners ON	BACT 6.5 LEL 6.5	BACT 18.4 Note (r) LEL 18.4	BACT 16.8 LEL 11.2	BACT 25.0 LEL 19.0	BACT 12.8 LEL 6.4

[County Rule 240, §308.1(a), (d), (e)][40 CFR 60.43a(b), (g)][40 CFR 60.333(a)]
[County Rule 360 §301]

Table 11
Emission Limits for the AVEF II Combined Cycle Systems During Periods of Startup or Shutdown (lb/event)

Device	NO_x	CO	VOC

Combustion Turbine #3 and #4 Combined during Startup	799.0	2,484.0	142.0
Combustion Turbine #3 and #4 Combined during Shutdown	124.0	712.0	44.0

Note 1: There is also a maximum pounds per hour limit of 2,520 lb/hr CO.

[County Rule 240, §308.1(a), (d), (e)]

Table 12
Hourly Emission Limits for the AVEF II Auxiliary Boiler (lb/hr)

Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**
Auxiliary Boiler For AVEF II	0.08	1.15	4.95	0.33	0.53

[County Rule 240, §308.1(a), (d), (e)]

Table 13
Additional Concentration or Rate Emission Limits for AVEF II

Device	**NO_x**	**CO**	**PM_{10} Solids (Filterable) Alone**	**PM_{10} Total (Filterable plus Condensable)**	**VOC**	**Other**
Each Combustion Turbine #3 or #4 Exhaust when Operating in Conditions Other than Startup and Duct Burners OFF	NS	NS	9.0 lb/hr	**BACT** 18.0 lb/hr Duct Burners OFF, 25.0 lb/hr Duct Burners ON **LEL** 15.0 lb/hr Duct Burners OFF, 19.0 lb/hr Duct Burners ON	NS	NS
Each Duct Burner Set #3 or #4 Exhaust	NS	NS	0.03 lb/mmBtu	NS	NS	NS
Each Combined Cycle System #3 or #4 Exhaust	**BACT** 2.0 ppm 3-hour rolling average Note (r)	**BACT** 3.0 ppm with Duct Burners ON and 2.0 ppm with Duct Burners	NS	NS	**BACT** 4.0 ppm with Duct Burners ON and 1.0 ppm with Duct Burners OFF, 3-hour average	**Ammonia** 10 ppm 24-hour rolling average

	LEL 2.0 ppm, 1-hour average **NSPS** 1.6 lb/MW-hrs	OFF, 3-hour rolling average **LEL** 2.0 ppm, with Duct Burners ON or OFF, 3-hour average			**LEL** 2.0 ppm with Duct Burners ON and 1.0 ppm with Duct Burners OFF, 3-hour average	
Auxiliary Boiler Exhaust	0.035 lb/mmBtu	0.150 lb/mmBtu				No more than 188 mmscf natural gas combusted per rolling 12-month period

[County Rule 240, §308.1(a), (d), (e)] [40 CFR 60.42a(a)(1)] [40 CFR 60.44a(d)(1)]
[40 CFR 60.332(a)(1)] [County Rule 360 §301] [40 CFR 60.46a(c)]

The following Notes apply to Tables 3 through 13.

a) NA (Not Applicable) means that the device does not emit the indicated pollutant.

b) NS (Not Specified) means that no additional Concentration or Rate limit is specified for that pollutant and device in Tables 7 or 13.

c) Startup is defined as the period starting when fuel is first combusted in the combustion turbine, and ending upon initiation of dry, low-NO_x operation as indicated by receipt of a Mode 6 signal from the turbine control system.

d) Shutdown is defined as the period of time following normal operations starting when the Mode 6 signal from the turbine control system is lost, and ending when fuel is no longer being combusted in the combustion turbine.

e) The rolling twelve month limits shall be calculated monthly using the data from the most recent calendar months, with a new 12-month period beginning on the first day of each calendar month.

f) For purposes of complying with 40 CFR Part 75, NO_x emissions during normal operations shall be calculated in accordance with 40 CFR Part 75, Appendix F and Appendix D.

[40 CFR 75 Appendix F]

g) To demonstrate compliance with 40 CFR 60 Subpart Da, NO_x emissions shall be calculated as required by 40 CFR 60.46a(k)(2)(iv). Data used to meet the requirements of 40 CFR 60.49a shall not include data substituted using the

missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75.
[40 CFR 60.47a(c)(2) and 60.46a(k)(2)(iv)] [County Rule 360 §301]

h) To demonstrate compliance with 40 CFR Subpart GG, NO_x emissions shall be calculated as required by 40 CFR 60.335(c)(1) unless the Combustion Turbines are installed with a Mark V or functionally equivalent controller programmed with an algorithm acceptable to the Administrator and Control Officer that continuously corrects for variations in ambient humidity, temperature, and pressure yielding a relatively constant NO_x concentration when corrected to 15 percent oxygen, in which case the CEM data can be used without the 40 CFR 60.335(c)(1) correction.
[40 CFR 60.335(c)(1)] [County Rule 360 §301.40]

i) In the event that the NO_x or CO analyzer measuring startup/shutdown emissions is not operational or cannot reliably document emissions, startup/shutdown emissions shall be calculated multiplying the appropriate startup/shutdown emission event rates in Tables 5 and 11 by the number of events. CO startup/shutdown emissions can also be calculated by monitoring the total elapsed time during the startup/shutdown sequence and multiplying by the startup/shutdown maximum pounds per hour limit of 2,520 lb/hr CO. An alternative emission rate can be used if such rate is demonstrated to the satisfaction of the Control Officer to be more representative of startup/shutdown emissions.

j) VOC, HAPs, and PM_{10} emissions from the AVEF I Combined Cycle Systems and Auxiliary Boiler during normal operations and startup/shutdown periods and CO and NO_x emissions during periods when the AVEF I Continuous Emission Monitors are not operational shall be calculated using the emission factors contained in the Permit Application dated April 2000 unless an alternative emission rate can be demonstrated to the satisfaction of the Control Officer to be more representative of emissions.

k) VOC, HAPs, and PM_{10} emissions from the AVEF II Combined Cycle Systems and Auxiliary Boiler during normal operations and startup/shutdown periods and CO and NO_x emissions during periods when the AVEF II Continuous Emission Monitors are not operational shall be calculated using the emission factors contained in the Permit Application dated November 2002 unless an alternative emission rate can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions.

l) PM_{10} emissions from the AVEF I Cooling Tower shall be calculated from the following equation:

PM_{10} Emissions (tons/yr) = Total Recirculation Rate(gallons/minute) *
TDS Concentration (milligrams/liter) *
6.905E-09;

Where the value 6.905E-09 is a conversion factor for cooling tower drift rate (0.001%), grams to tons, liters to gallons, minutes to year, and one 31.5% of total particulate as PM_{10}; and the Total Recirculation Rate is the total for all cooling tower cells.

m) PM_{10} emissions from the AVEF II Cooling Tower shall be calculated from the following equation:

PM_{10} Emissions (tons/yr) = Total Recirculation Rate(gallons/minute) * TDS Concentration (milligrams/liter) * 3.452E-09;

Where the value 3.452E-09 is a conversion factor for cooling tower drift rate (0.0005%), grams to tons, liters to gallons, minutes to year, and 31.5% of total particulate as PM_{10}; and the Total Recirculation Rate is the total for all cooling tower cells.

n) SO_2 emissions shall be calculated from fuel usage during normal operations and startup/shutdown and the sulfur content of the fuel as determined by Condition 20.G of this permit.

o) The rolling 3-hour average CO limit in Tables 7 and 13 shall be calculated in proportion to the time that the Duct Burners are ON. For example, for AVEF I, if in a rolling 3-hour period, the Duct Burners were ON for 1 hour and OFF for 2 hours, the permit limit is 13.4 ppm (1/3 x 20 + 2/3 x 10 = 13.4) for that period.

p) Unless otherwise stated, the PM_{10} emission limits include both solid (filterable) and condensable particulate matter. Filterable PM_{10} is measured with 40 CFR Part 60 Appendix A Method 5.

q) Concentration limits are parts per million by volume corrected to 15% oxygen on a dry basis, unless otherwise specified.

r) BACT emission limits or averaging period for NO_x may be lowered. Refer to Condition 19.F.

s) When multiple or alternative limits apply, the most stringent governs.

t) A startup or shutdown "event" is a single occurrence of a startup or a shutdown as defined in Notes c) and d) above.

u) The limitations in Tables 4, 6, 7, 10, 12 and 13 apply at all times except during periods of startup, shutdown, or malfunctions.

[40 CFR 60.46a(c)] [County Rule 360 §301]

3) Offsite Sulfur Oxides limits:

The Permittee shall not emit into the ambient air any sulfur oxide in such manner and amounts as to result in ground level concentrations at any place beyond the premises on which the source is located exceeding the limits shown in Table 14:

Table 14
Sulfur Dioxide Ambient Concentration Limits

Concentration of Sulfur Dioxide (ug/cubic m)	Averaging Time (hours)
850	1
250	24
120	72

[SIP Rule 32 F]

4) Particulate Matter Limits (General):

The Permittee shall not cause, allow or permit the emission of particulate matter, caused by combustion of fuel from any emissions unit in excess of the amounts calculated by the following equation:

$E = 1.02\ Q^{0.769}$ where:

E= the maximum allowable particulate emissions rate in pounds-mass per hour.
Q= the heat input in million Btu per hour.

[ARS §49-106, State Rule R18-2-719.C.1 (R9-3-519.C.1), SIP Rule 31(H)]

5) Opacity Limits

The Permittee shall not discharge into the ambient air from any single source of emissions any air contaminant other than condensed water containing no more than analytical trace amounts of other chemical elements or compounds, in excess of 20 percent opacity, except the following:

a) Startup and Shutdown: Visible emissions exceeding the opacity standards for short periods of time resulting from startup, shutdown, soot blowing or unavoidable combustion irregularities which do not exceed three minutes in length shall not constitute a violation provided that the Control Officer finds that adequate control technology has been applied.
b) Emergencies: Unavoidable combustion irregularities which exceed three minutes shall not constitute a violation of these Permit Conditions providing the owner or operator demonstrate to the Control Officer's satisfaction that an emergency exists in accordance with County Rule 130 §201.

[County Rule 300 §§ 301, 302.1,2] [40 CFR 60.42a(b)]

Except as otherwise provided in Regulation I, Rule 4, Exceptions, the opacity of any plume or effluent from any source of emissions, other than uncombined water, shall not be greater than 40 percent opacity as determined by Reference Method 9 in the Arizona Testing Manual.

[SIP Rule 30]

B. Emission Limitations For The Diesel Fire Pump Engine and Back-up Generator:

The Permittee shall not cause, allow or permit the emissions from either the diesel fire pump engine or the back-up generator to exceed 20 percent opacity, 3-minute average, except for short periods of time resulting from startup, shutdown, or unavoidable combustion irregularities which do not exceed three minutes in length.

[County Rule 300 §§301, 302]

19. OPERATIONAL REQUIREMENTS

A. Facility – Wide Operational Requirements:

1) The Permittee shall combust only pipeline quality natural gas with a sulfur content of 0.0075 grains per dry standard cubic foot or less in all devices except the diesel fire pump engine and back-up generator, which shall burn only commercially available diesel fuel with sulfur content of 0.05 percent by weight or less.
[County Rule 240 §308.1(a), (d), (e)] [County Rule 320 §306.4] [40 CFR 60.333(b)]
[County Rule 360 §301.40] [40 CFR 60.43a(b)]

2) The Permittee shall not emit gaseous or odorous air contaminants from equipment, operations or premises under his control in such quantities or concentrations as to cause air pollution.
[County Rule 320 §300] [locally enforceable only]

3) Materials including, but not limited to, solvents or other volatile compounds, paints, acids, alkalies, pesticides, fertilizer and manure shall be processed, stored, used and transported in such a manner and by such means that they will not unreasonably evaporate, leak, escape or be otherwise discharged into the ambient air so as to cause or contribute to air pollution. Where means are available to reduce effectively the contribution to air pollution from evaporation, leakage or discharge, the installation and use of such control methods, devices or equipment shall be mandatory.
[County Rule 320 § 302] [locally enforceable only]

4) Where a stack, vent or other outlet is at such a level that air contaminants are discharged to adjoining property, the Control Officer may require the installation of abatement equipment or the alteration of such stack, vent, or other outlet to a degree that will adequately dilute, reduce or eliminate the discharge of air contaminants to adjoining property.
[County Rule 320 § 303] [locally enforceable only]

B. Operational Requirements for the Combined Cycle Systems:

Each AVEF I and AVEF II Combined Cycle System shall operate such that the total combined hours in both the startup and shutdown modes for each system does not exceed 1,050 hours per year for each Combined Cycle System, calculated on a rolling 12 calendar month basis. For purposes of this Permit Condition, startup and shutdown are as defined in Notes (c) and (d) after Table 13 in Permit Condition 18.A.2.

[County Rule 240 §308.1(a), (d), (e)]

C. Operational Requirements for the Auxiliary Boiler:

The Permittee shall operate the AVEF I auxiliary boiler less than 6,000 hours per rolling 12-month period. The permittee shall combust no more than 188 mmscf of natural gas per rolling 12-month period in the AVEF II auxiliary boiler.

[County Rule 240 §308.1(a), (d), (e)]

D. Operational Requirements for the Cooling Tower:

1) The AVEF I cooling tower shall at all times be equipped and maintained with high efficiency drift eliminators certified by the cooling tower vendor to achieve less than 0.001 percent drift. The total dissolved solids (TDS) content of the cooling water in the cooling tower shall not contain more than 12,000 milligrams per liter (mg/l) TDS.
2) The AVEF II cooling tower shall at all times be equipped and maintained with high efficiency drift eliminators certified by the cooling tower vendor to achieve less than 0.0005 percent drift. The total dissolved solids (TDS) content of the cooling water in the cooling tower shall not contain more than 12,000 milligrams per liter (mg/l) TDS.

[County Rule 240 §308.1(a), (d), (e)]

E. Operational Requirements for the Diesel Fire Pump Engines and Back-up Generator Engines:

1) The Permittee shall operate the Diesel Fire Water Pump Engines only for emergency conditions or routine maintenance checks.
2) The Permittee shall operate the Diesel Back-up Generators only for emergency conditions or routine maintenance checks.

[County Rule 240 §308.1(a), (d), (e)]

F. Operational Requirements for the Selective Catalytic Reduction Emission Control Systems

1) The Permittee shall install, operate, and maintain a Selective Catalytic Reduction (SCR) system as part of each AVEF I Combined Cycle System. The AVEF I SCR system shall be designed and installed to achieve a 2.5 ppm (dry, corrected to 15% oxygen) NO_x emission concentration, and the Permittee shall provide evidence of such design to the Control Officer prior to installation. During the first two years of commercial operation, the NO_x emission limit shall be 3.0 ppm on a 3-hour rolling average basis and the annual and hourly mass emission rates of NO_x shall be as stated in Tables 3 and 4 and the NO_x emission limit shall be as stated in Table 7 of this Permit. If, after the first two years of commercial operation, it can be shown that continual compliance can be demonstrated at levels between 2.5 and 3.0 ppm (not including startups/shutdowns and malfunctions, and considering the differences between normal operations and normal operations with duct burner firing on), then the NO_x emission limit in Table 7 will be lowered to the demonstrated compliance concentration between 2.5 and 3.0 ppm for normal operations and normal operations with duct burner firing on, and the mass emission rate limits in Tables 1, 2, 3, 4 and 7 shall be lowered proportionately to the reduction in emission concentration.

2) To ensure that the AVEF I SCR system is properly operated to achieve the design control rate of 2.5 ppm NO_x during the first two years of commercial operation, the equivalent anhydrous ammonia injection rate shall not be less than the value calculated as described in Appendix D of this Permit, measured by the ammonia flowmeter required in Condition 20.I. After the initial two year period, the final NO_x limit shall be determined, and the minimum ammonia injection rate monitoring requirement shall no longer apply.
3) The Permittee shall install, operate, and maintain a Selective Catalytic Reduction (SCR) system as part of each AVEF II Combined Cycle System. The AVEF II SCR system shall be designed and installed to achieve a 2.0 ppm (dry, corrected to 15% oxygen) NO_x emission concentration on a 1-hour average basis, and the Permittee shall provide evidence of such design to the Control Officer prior to installation. [locally enforceable only]
4) For the first two years of operation starting on the date of initial startup, the AVEF II SCR systems shall be installed, operated and maintained such that the emissions of NO_x from each AVEF II Combined Cycle System shall not exceed 2.0 ppm (dry, corrected to 15% O_2), on a three-hour average, duct burners ON, excluding startup and shutdown periods as defined in Condition 18.A.2. After the first two years of operation, emissions of NO_x shall not exceed 2.0 ppm (dry, corrected to 15% O_2), on a one-hour average, duct burners ON, excluding startup and shutdown periods as defined in Condition 18.A.2, unless an acceptable demonstration is submitted as a written request to the Control Officer and the Administrator prior to the two year anniversary of operation seeking a change from the 2.0 ppm on a 1-hour basis limit and stating the suggested averaging time. The demonstration shall provide all supporting documentation demonstrating the facility's inability to meet the 2.0 ppm on a 1-hour basis limit despite proper operation and maintenance of the SCR system. If the Control Officer and Administrator conclude that the demonstration is acceptable, the Control Officer and the Administrator shall set a new NO_x averaging time at a level that the Permittee can consistently and reasonably meet based upon their evaluation of the demonstration report submitted by the Permittee. The new NOx emission limit shall be incorporated into the permit through a significant permit revision. However, the new emission rate shall not be greater than 2.0 ppmvd on a rolling 3-hour average, excluding startup and shutdown periods as defiined in this Permit. The emission limits in Tables 1, 2, 8, 10, and 13 shall be adjusted if necessary to reflect the changes in emission concentration.

[County Rule 240 §308.1(a), (d), (e)][federally and locally enforceable]

5) The Permittee shall submit an approvable Operations and Maintenance (O&M) plan to the Department for each SCR system required by these Permit Conditions. The plans shall be in a format acceptable to the Department and shall specify the procedures used to maintain the SCR system. The O&M plan shall be submitted within 30 days after the equipment covered has been started up.
6) The Permittee shall at all times comply with the currently approved version of the O&M Plan.
7) The SCR control system shall be designed so it will not inject ammonia into the SCR system when the inlet temperature to the catalyst is less than the Minimum Catalyst Temperature to be established as part of the O&M Plans.

[County Rule 210 §302.1(c)(1)]

G. Operational Requirements for the Catalytic Oxidation Emission Control Systems

1) The Permittee shall install, operate, and maintain a Catalytic Oxidation emission control system (CAT-OX) as part of each AVEF II Combined Cycle System. The AVEF II CAT-OX system shall be designed and installed to achieve a 2.0 ppm (dry, corrected to 15% oxygen) CO emission concentration on a 3-hour average basis with duct burners ON or OFF, excluding startup and shutdown periods as defined in Condition 18.A.2. The Permittee shall provide evidence of such design to the Control Officer prior to installation.

[County Rule 240 §308.1(a),(d),(e)][locally enforceable]

2) The Permittee shall install, operate, and maintain a Catalytic Oxidation emission control system (CAT-OX) as part of each AVEF II Combined Cycle System. The AVEF II CAT-OX system shall be designed and installed to achieve a 3.0 ppm (dry, corrected to 15% oxygen) CO emission concentration on a 3-hour average basis with duct burners ON, a 2.0 ppm (dry, corrected to 15% oxygen) CO emission concentration on a 3-hour average basis with duct burners OFF, and the Permittee shall provide evidence of such design to the Control Officer prior to installation. [federally and locally enforceable]

3) The Permittee shall submit an approvable Operations and Maintenance (O&M) plan to the Department for each CAT-OX system required by these Permit Conditions. The plans shall be in a format acceptable to the Department and shall specify the procedures used to maintain the CAT-OX system. The O&M plan shall be submitted within 30 days after the equipment covered has been started up.

4) The Permittee shall at all times comply with the currently approved version of the O&M Plan.

[County Rule 210 §302.1(c)(1)]

H. Operational Requirements for the Continuous Emissions Monitoring Systems

1) The CEMS shall meet or exceed all applicable design, installation, operational, quality assurance, and all other applicable requirements of 40 CFR Parts 60 and 75. If there is a conflict between 40 CFR Parts 60 and 75, Part 75 governs.

2) The fuel flow monitor shall meet or exceed specifications contained in Section 2.1.5.1 of Appendix D to Part 75.

3) The Permittee shall ensure that the CEMS are in operation and monitoring unit emissions at all times that the Combined Cycle Systems combust any fuel except during periods of calibration, quality assurance, preventive maintenance, repair, back-ups of data from the data acquisition and handling system, or recertification. Malfunctions shall be recorded and reported as required under 40 CFR Part 60 and Part 75. If there is a conflict between 40 CFR Parts 60 and 75, Part 75 governs.

4) The Permittee shall ensure that the design, installation, operation, maintenance, O&M/QA Plan(s), and on-site spare parts inventory are sufficient to ensure that the CEMS meet the data capture requirements of Permit Condition 20.E and 40 CFR Parts 60 and 75, whichever is more stringent.

5) The Permittee shall submit an approvable Operations and Maintenance (O&M) plan to the Department for each Continuous Emissions Monitoring System (CEMS) required by these Permit Conditions. The plans shall be in a format acceptable to the Department and shall specify applicable operating parameters

necessary to ensure continuous and accurate emissions monitoring. The O&M plan shall be submitted within 30 days after the equipment covered has been started up.

6) The Permittee shall submit an approvable Quality Assurance Plan (QAP) to the Department for each CEMS required by these Permit Conditions. The plans shall be in a format acceptable to the Department. If the QAP plan has not been approved as part of the application for this permit, then the QAP shall be submitted within 30 days after the equipment covered has been started up. The Permittee shall at all times comply with the QAP.
7) A combined O&M Plan and Quality Assurance Plan for both CEMS may be submitted.
8) The Permittee shall at all times comply with the currently approved version of the O&M and QA Plans.
9) Within 90 days after commencement of commercial operations (as defined by 40 CFR 72.2), the Permittee shall certify the CEMS with a Relative Accuracy Test Audit (RATA), linearity check, cylinder gas audit (CGA), bias check, 7-day calibration error check, and cycle time check.
10) The Permittee shall at least annually conduct a RATA and bias check in accordance with Part 75 requirements. The Permittee shall at least quarterly conduct linearity checks and cylinder gas audits (CGA) in accordance with Part 60 and Part 75 requirements. The Permittee shall at least daily conduct calibration error and drift checks when combusting fuel and at least a calibration check prior to startup of the Combined Cycle System. More frequent audits and checks shall be conducted as required by 40 CFR Parts 60 and 75.
11) The Permittee shall ensure that all calibration gases (including zero gases) are certified and current at all times.
12) The Permittee shall re-calibrate any CEMS after any maintenance activity that could affect the system calibration and shall re-certify as required by and within the time periods required by 40 CFR 75.20(b) whenever the Permittee makes a replacement, modification, or change that may significantly affect the ability of the system to accurately measure or record emissions.
13) The Permittee shall develop and implement daily, monthly, quarterly, and annual maintenance checklists to ensure proper operation and accuracy of the CEMS. The checklists will be established as part of the O&M and QA Plans.
14) The Permittee shall maintain records of all certifications, calibrations, testing, maintenance (including completed maintenance checklists), and repairs made to the CEMS.

[County Rule 210 §302.1(c)(1)][40 CFR 60 Subparts Da and GG]
[40 CFR 75 Subparts A, B, C, Appendix A, Appendix B] [County Rule 360 §301]

I. <u>Operational Requirements During the Commissioning Period of for AVEF II Combustion Turbines</u>

1) The conditions in this Permit Condition apply only during the commissioning period of each Combined Cycle System. The commissioning period begins when a Combined Cycle System becomes operational (i.e., after turbine steam blows/HRSG boilout are completed) and ends when the Permittee has completed the air quality compliance source emissions test as required by Permit Condition 22 for that Combined Cycle System; but no later than 180 days after the first time that natural gas is combusted in the Combined Cycle System for any purpose.

The turbine steam blows/HRSG boilout procedures are considered completed when the steam cleanliness test meets the manufacturers requirements for design steam pressure and flow conditions. Permittee shall notify the Division within 24 hours of each Combined Cycle System becoming operational.

2) The Permittee shall minimize emissions of CO and NO_x from the Combined Cycle Systems to the maximum extent practicable during the commissioning period.
3) At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the Combined Cycle Systems shall be tuned to minimize the emissions of CO and NO_x.
4) At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the SCR and CAT-OX system on each Combined Cycle Systems shall be installed, adjusted, and operated to minimize the emissions of CO and NO_x.
5) Coincident with the completion of the commissioning period as defined in Condition 19.I.(1), the Permittee shall comply with the hourly emission limits for NO_x and CO emission limitations specified in Tables 10, 11, and 13 of Permit Condition 18.
6) The Permittee shall submit a plan to the Control Officer at least four weeks prior to first firing of any Combined Cycle System describing the procedures to be followed during the commissioning of the System. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low- NOx combustors, the installation and operation of the SCR and CAT-OX, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Combined Cycle System without abatement by the SCR and/or CAT-OX.
7) During the commissioning period, the Permittee shall demonstrate compliance with Permit Conditions 19.I.(10) through the use of properly operated and maintained continuous emission monitors (CEM) and data recorders for the following parameters:
    a. firing hours for each gas turbine and each HRSG
    b. fuel flow rates to each gas turbine and each HRSG
    c. stack gas NO_x emission concentrations
    d. stack gas CO emission concentrations
    e. stack gas O3 concentrations
8) The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Combined Cycle Systems. The Permittee shall use calibrated permanent or portable CEM, EPA Reference Method 19, or other Division-approved methods to calculate heat input rates, NO_x mass emission rates, CO mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The analyzers used during commissioning shall be ranged and calibrated at anticipated missing data substitution emission levels. All records shall be retained on site for at least 5 years from the date of entry and made available to Division personnel upon request.
9) Operation of a Combined Cycle System without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or CAT-OX fully operational.

10) The total mass emissions of NO_x, CO, VOCs, PM_{10}, sulfur dioxide, and hazardous air pollutants that are emitted by the Combined Cycle Systems during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in Permit Condition 18 and shall be included in the annual emissions report specified in Permit Condition 16.
11) Prior to the end of the Commissioning Period, the Permittee shall conduct a Division-approved air quality compliance source emissions test in accordance with Permit Condition 22.

[County Rule 210 §§302.1.b, 302.1.d & 302.1.e] [locally enforceable only]

20. MONITORING/RECORDKEEPING REQUIREMENTS

A. The Permittee shall hourly monitor and record the hours of operation and operating mode (e.g., Mode 6 or other modes) of each Combined Cycle System; the Combined Cycle System exhaust temperature prior to entering the Selective Catalytic Reduction System; the amount of natural gas combusted in each of the Combined Cycle Systems, and the electrical energy output of each Combined Cycle System. The Permittee shall monthly calculate the twelve-month total hours of operation in each mode for each Combined Cycle System.

[County Rule 210 §302.1(c)(1)]

B. The Permittee shall monitor and daily record the hours of operation, monthly calculate the 12-month total hours of operation, and monthly determine the amount of natural gas combusted (based on hours of operation) in the AVEF I auxiliary boiler. Prior to startup of the AVEF II auxiliary boiler, the Permittee shall install a fuel flow meter to the AVEF II auxiliary boiler that meets the accuracy specifications of the American Gas Association Report 3 or ASME MFC-3M-1989 or equivalent specification. The Permittee shall monitor and daily record the amount of natural gas combusted and monthly calculate the twelve-month total amount of natural gas combusted (based on the fuel meter) in the AVEF II auxiliary boiler.

[County Rule 210 §302.1(c)(1)][40 CFR 60.48c(g)] [County Rule 360 §301.5]

C. The Permittee shall record the actual hours of operation and the reason for operation of the diesel fire water pump engines and the diesel back-up generators and the nature of the emergency or maintenance check that caused the engines to be used. The Permittee shall monthly calculate the twelve-month total hours of operation.

[County Rule 210 §302.1(c)(1)]

D. Within 90 days after commencement of commercial operation as defined by 40 CFR 72.2, the Permittee shall install, calibrate, certify, and operate a continuous emission monitor for each of the Combined Cycle System exhaust stacks to continuously measure carbon monoxide, oxides of nitrogen, and oxygen content of the exhaust stream in accordance with 40 CFR 60 Subpart Da and 40 CFR 75 requirements. Hourly average, rolling three-hour, and rolling 24-hour average values shall be continuously recorded.

[County Rule 210 §302.1(c)(2)][40 CFR 60 Subpart Da][40 CFR Part 75]
[County Rule 360 §301.3]

E. The continuous emission monitors must obtain valid data for at least 75 percent of the operating hours in at least 22 of every 30 successive combustion turbine system operating days defined as a 24-hour period beginning at 12:01 AM and ending at 12:00 midnight during which natural gas is combusted in the combustion turbine and/or the duct burner at any time during the 24 hour period for any purpose. If this minimum data requirement cannot be met with a continuous monitoring system, the Permittee shall supplement emission data with other monitoring systems approved by the Administrator and the Control Officer or the reference methods and procedures as described in 40 CFR 60.47a(h).

[County Rule 210 §302.1(c)(2), County Rule 360, 40 CFR 60 Subpart Da, §60.47a(f)]

F. Within 90 days after the commencement of commercial operations as defined by 40 CFR 72.2, the Permittee shall install, calibrate, certify, and operate natural gas fuel flow meters on each fuel line to monitor the unit-specific fuel flow to each of the Combined Cycle Systems.

[County Rule 210 §302.1(c)(2)][40 CFR Part 75]

G. The Permittee shall monitor for compliance with the sulfur dioxide limits of Tables 1, 2, 3, 4, 8, 9, 10, and 14 of this permit by obtaining and recording the sulfur content of the pipeline quality natural gas used in the Combined Cycle Systems using the following custom monitoring schedule:

1) The Permittee shall monitor sulfur content of the pipeline quality natural gas at least once every calendar quarter.
2) If at any time a fuel sulfur analysis indicates noncompliance with the fuel sulfur limit in Condition 19.A.1 of this Permit, the Permittee shall notify the Administrator and the Department of such excess emissions within one week of the analysis.
3) In the event of such noncompliance, the Permittee shall conduct fuel sulfur monitoring weekly until notified by the Administrator and the Department that less frequent monitoring is acceptable.
4) The Permittee shall determine compliance with the sulfur content limit in Condition 19.A.1 of this Permit by using measurement methods ASTM Method D5504-94, ASTM Method D172-80, ASTM Method D3031-81, ASTM Method D3246-81, or ASTM Method D4084-82 either at the site or upstream or downstream of the site. If the applicable ranges of these ASTM methods are not adequate to measure the levels of sulfur, dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator and the Control Officer.

[County Rule 210 §302.1(c)(2)][40 CFR 60.335(d), (e), §334(b)(2)]

H. The Permittee shall obtain and record the Gross Caloric Value of the natural gas used in the Combined Cycle Systems and the Auxiliary Boilers as required by 40 CFR Part 75, Appendix D at least as frequently as required by 40 CFR Part 75, Appendix D and Appendix G.

[County Rule 371] [40 CFR 75]

I. Within 90 days after the commencement of commercial operations as defined by 40 CFR 72.2, the Permittee shall install, certify, and operate on each SCR system monitors to measure the ammonia injection rate. The flow meters will be sampled by a data acquisition system at a frequency of no less than once every 15 minutes and averaged into rolling 24 hours periods. These data will be used to verify compliance with the ammonia emission limits of Tables 7 and 13 and the emissions testing requirements of Table 15.

[County Rule 210 §302.1(c)(1)]

J. The Permittee shall monthly inspect the Wet Cooling Towers drift eliminators for proper installation, maintenance, and operation. The results of the inspection shall be recorded in a facility log.

[County Rule 210 §302.1(c)(2)]

K. The Permittee shall daily monitor and record the conductivity of each of the cooling towers water and shall monthly monitor and record the Total Dissolved Solids (TDS) content of each cooling tower water.

[County Rule 210 §302.1(c)(1)]

L. The Permittee shall monthly conduct a facility walk-through and observe visible emissions from each Combined Cycle System exhaust stack, the Auxiliary Boilers, the diesel-fueled Fire Water Pump Engines, and the diesel-fueled Back-up Generators. The Permittee shall log the visual observations, including the date and time when that reading was taken, results of the reading, name of the person who took the reading and any other related information.

[County Rules 300, 210 §302.1(c)(1) and SIP Rule 30]

M. If visible emissions are observed from any device other than the Combined Cycle Systems capable of emitting any air contaminant other than condensed water containing no more than analytical trace amounts of other chemical elements or compounds and the facility has never had an opacity violation in the 12 months preceding the observation; the Permittee shall obtain an opacity reading conducted in accordance with EPA Reference Method 9 by a certified visible emissions (VE) reader. This reading shall be taken within 3 days of the observance of visible emissions and taken weekly thereafter during each week that the unit is in operation until there are no visible emissions. If the problem is corrected before three days has passed, and no emissions are visible, the Permittee shall not be required to conduct the certified reading. The Permittee shall log the visual observations, including the date and time when that reading was taken, results of the reading, name of the person who took the reading and any other related information. If an opacity violation has occurred at the facility in the 12 months preceding the observation of visible emissions, the required EPA Reference Method 9 opacity reading by a certified visible emissions (VE) reader shall be taken within 24 hours of the observation of visible emissions.

[County Rule 210 §302.1(c)(1)] [SIP Rule 31]

N. Opacity shall be determined by observations of visible emissions conducted in accordance with 40 CFR Part 60 Appendix A, Method 9, except opacity of visible emissions from intermittent sources as defined by County Rule 300 §201. Opacity of visible emissions from intermittent sources shall be determined by observations conducted in accordance with 40 CFR Part 60 Appendix A, Method 9, except that at least 12 rather than 24 consecutive readings shall be required at 15-second intervals for the averaging time.

[County Rule 300 §§501, 502] [locally enforceable only]

O. The Permittee shall monitor for compliance with the particulate matter emissions limits of the permit by taking a visual emission observation of the stack emissions from each Combined Cycle System during each week of operation that the equipment was used more than 10 hours. If emissions are visible, the Permittee shall obtain an opacity reading conducted in accordance with 40 CFR Part 60 Appendix A, Method 9 by a certified reader. This reading shall be taken within 3 operating days of the visible emission and taken thereafter weekly for each week when operations occur until there are no visible emissions. If the condition causing the visible emissions is eliminated before three days have passed, and no emissions are visible, the Permittee shall not be required to conduct the certified reading. The Permittee shall log the visual observations, including the date and time when that reading was taken, results of the reading, name of the person who took the reading and any other related information. If the visible emissions are present, the Control Officer may require emissions testing by other approved Reference Methods such as 40 CFR 60 Appendix A Method 5 to demonstrate compliance with the particulate matter emission limits of these Permit Conditions.

For purposes of these Permit Conditions, a certified visible emissions reader shall mean an individual who, at the time the reading is taken, is certified according to the County Rule Appendix C, Section 3.4.

[County Rule 210 §302.1.c(2) and SIP Rule 31]

P. The Permittee shall maintain a log of complaints of odors detected off-site. The log shall contain a description of the complaint, date and time that the complaint was received, and if given, name and/or phone number of the complainant. The logbook shall describe what actions were performed to investigate the complaint, the results of the investigation, and any corrective actions that were taken.

[SIP Rule 32][County Rules 320 and 210 §302.1]

Q. The Permittee shall maintain a file of all measurements as required by County Rule 210 §302.1.d, including continuous emission monitoring system emission records; operating parameter records; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 75 Subpart F and 40 CFR 60.48c(i) recorded in a permanent form for at least five years.

[40 CFR 60.48c(i)][40 CFR Part 75 Subpart F][County Rules 210, 360 and 371]

R. The Permittee shall keep all the records of the fuel supplier certification for the diesel fuel being combusted for at least five years. The supplier certification shall include:

1) the name of the supplier,
2) the sulfur content of the fuel,
3) the method used to determine the sulfur content of the fuel,
4) the date that the fuel was delivered to the site, and
5) the date that the fuel was sampled for sulfur content.

[County Rules 320, 210 §302.1.c and SIP Rule 32]

S. In addition to summary information provided in the Compliance Report submitted under Condition 21.D, the Permittee shall maintain on site at least the following information that demonstrates the conclusions reached in the Compliance Report:

1) Hours of operation and amount of fuel burned each hour for each combustion turbine; hours of operation and amount of fuel burned in each auxiliary boiler; and hours of operation for each of the diesel fire pump and back-up generator engines.
[County Rules 210 and 320] [SIP Rule 32]
2) Electrical energy output of each Combined Cycle System for each hour of operation. [County Rules 360 §301 and 40 CFR 60.47a]
3) Dates on which visible emissions observations were taken, the test method used, and the results of the observations.
[County Rules 300, 210 and SIP Rule 30]
4) Continuous Emissions Monitoring data related to the emission limits contained in this permit, calibrations, quality assurance, performance demonstrations, and certifications for the reporting period.
[County Rule 210]
5) Stack emissions test results related to emission limits and/or operational requirements in this Permit.
[County Rule 210]
6) Cooling tower inspection log and results of conductivity and TDS monitoring.
[County Rule 210]
7) Odor log.
[County Rule 210]
8) Any other records and reports required by any Permit Condition contained in this Permit.
[County Rule 210]

21. REPORTING REQUIREMENTS

A. The Permittee shall file a written notice with the Control Officer as described in 40 CFR 60.4, 40 CFR 60.7, 40 CFR 60.19, and 40 CFR 60.48c(a) as follows:
1) A notification of commencement of construction or reconstruction of the facility postmarked within 30 days of such date.
2) A notification of the actual date of initial startup of each of the Combustion Turbines, Duct Burners, and Auxiliary Boiler postmarked within 15 days of such dates.
3) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under 40 CFR 60.14(e). This notice shall be postmarked within 60 days or as soon as commenced and shall include information describing the precise nature of the change, present and proposed emissions control systems, productive capacity of the facility before and after the change, and the expected completion date of the change.
4) In accordance with 40 CFR 60.4, the notifications required by this Permit Condition shall be sent in duplicate to the Director, Air Division, Region IX of the United States Environmental Protection Agency (USEPA). A copy of the notifications shall be sent to the Control Officer.
[County Rule 360 §301] [40 CFR 60.4(a), (b), (D)]
[40 CFR 60.7(a)] [40 CFR 60.14(e)] [40 CFR 60.19] [40 CFR 60.48c(a)]

B. In addition to other reports required by this Permit, the Permittee shall report nitrogen oxides concentrations to the Administrator and the Control Officer semiannually for each six month period post marked no later than the 30th day following the end of each six month period as required by 40 CFR 60.7(c), 40 CFR 60.7(d), 40 CFR 60.49a and 40 CFR 60.47a(c)(2) for the duct burners as follows:

1) The initial performance evaluation test data of the Continuous Emissions Monitor and any subsequent performance evaluation test data.
[40 CFR 60.49a(a)] [County Rule 360 §301.3]

2) For each 24-hour period (beginning at 12:01 AM and ending at 12:00 midnight and during which natural gas was combusted in the duct burner for the entire 24 hours) the following information shall be reported to the Administrator and the Control Officer:
   a) Calendar date
   b) Average nitrogen oxide emission rate in terms of lb/MW-hr for each rolling 30-day period in the quarter; reasons for non-compliance with the emission limits; and, description of corrective action taken.
   c) Identification of each 24-hour period (beginning at 12:01 AM and ending at 12:00 midnight and during which natural gas was combusted in the duct burner for any purpose for the entire 24 hours) for which nitrogen oxide or diluent data have not been obtained for at least 18 of the operating hours in that 24-hour period; justification for not obtaining sufficient data; and description of corrective actions taken.
   d) Identification of the times when emissions data have been excluded from the calculation rates because of startup, shutdown, malfunction, or other reasons, and justification for excluding data for reasons other than startup, shutdown, or malfunction.
   e) Identification of the “F” factor used for calculations and method of determination.
   f) Identification of times when hourly averages have been obtained based on manual sampling methods.
   g) Identification of the times when the pollutant concentrations exceeded full span of the continuous monitoring system.
   h) Description of any modifications to the continuous emissions monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications required by 40 CFR Part 75.
[40 CFR 60.49a(b)] [County Rule 360 §301.3]

3) If the minimum quantity of nitrogen oxides continuous emissions monitoring data as required by Permit Condition 21.B. is not obtained for any 30 successive 24-hour periods as defined in Permit Condition 21.B.2.(c), and manual methods are substituted, the following information will be reported:
   a) The number of hourly averages available for outlet emission rates from the Combined Cycle System.
   b) The standard deviation of hourly averages for outlet emission rates.
   c) The lower confidence limit for the mean outlet emission rate.
   d) The applicable potential combustion concentration.
   e) The ratio of the upper confidence limit for the mean outlet emission rate and the allowable emission rate as applicable.
[40 CFR 60.49a(c)] [County Rule 360 §301.3]

4) For any periods for which nitrogen oxides emissions data are not available, the Permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system are to be compared with operation of the control system before and following the period of data unavailability.
[40 CFR 60.49a(f)] [County Rule 210 §§302.1d(2)] [County Rule 360 §301.3]

5) For both nitrogen oxides and carbon monoxide continuous emission monitoring, the Permittee shall submit a signed statement Indicating whether:
   a) The required continuous emission monitoring system calibration, span, and drift checks or other period audits have or have not been performed.
   b) The data to show compliance was or was not obtained in accordance with approved methods and procedures and is representative of plant performance.
   c) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
   d) Compliance with the standards has or has not been achieved during the reporting period.

[40 CFR 60.49a(g)] [County Rule 210 §§302.1d(2)] [County Rule 360 §301.3]

6) The Permittee shall submit an excess emissions report for NO_x emissions from the duct burners and a NO_x continuous emissions monitoring system (CEMS) performance report as required by 40 CFR 60.7(c) and the summary report form required by 40 CFR 60.7(d). The reports shall be prepared in accordance with 40 CFR 60.7(c)(1), (2), (3) and 40 CFR 60.7(d). When no excess emissions have occurred or the CEMS have not been inoperative, repaired, or adjusted, such information shall be stated in the reports. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and the CEMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form specified in 40 CFR 60.7(d) shall be used and no excess emissions report shall be required.
[40 CFR 60.7(c) and (d)] [County Rule 360 §301.1]

7) The Permittee may submit electronic reports for the information required by this Permit upon coordination with the Administrator and the Control Officer to develop the required format and including a signed statement that indicates whether compliance with the emissions standards and minimum data requirements of this Permit were achieved during the reporting period.
[40 CFR 60.49a(j)] [County Rule 360 §301.3]

8) Data reported for duct burners under Permit Condition 21.B. shall not include data substituted using the missing data procedures in Subpart D of Part 75 nor shall the data have been bias adjusted according to the procedures of Part 75.
[40 CFR 60.47a(c)(2] [County Rule 360 §301.3].

C. In addition to the reports filed by the Permittee in accordance with 40 CFR Part 75 Subpart G, the Permittee shall electronically report to EPA the data and information as required by 40 CFR Part 75.64 on a quarterly basis. Quarterly submittals shall include facility data, unit emission data, monitoring data, control equipment data, monitoring plans and quality assurance data and results.

[40 CFR 75 Subpart G, County Rules 210 and 371]

D. The Permittee shall file a semiannual Compliance Report no later than April 30th, and shall report the compliance status of the source during the period between October 1st of the previous year and March 31st of the current year. The second certification shall be submitted no later than October 31st and shall report the compliance status of the source during the period between April 1st and September 30th of the current year. The initial Compliance Report shall reflect the compliance status of the source beginning with the date of the permit issuance. The Compliance Report shall include the following information:
   1) Summary of compliance status with respect to each condition contained in this permit; including, but not limited to a description of the basis for the summary conclusions with respect to each permit condition.
   2) Description of and an explanation for any deviations from any permit condition at any time.
   3) A certification that construction has not been discontinued or suspended for 18 months or more. Once construction is complete, a certification that the facility has been constructed as required by this Permit and construction has been completed. [40 CFR 52.21][County Rule 210 §302.1e(1)]

22. TESTING REQUIREMENTS

A. The following apply to all emissions testing required by this Permit Condition:
   1) The Permittee shall submit an approvable test protocol to the Department, for review and approval at least 30 days prior to the emissions test. A fee for each stack to be tested shall be submitted with the test protocol as required by County Rule 280.

      [County Rule 270 and 280 §301.5]

   2) The Permittee shall notify the Department in writing at least two weeks in advance of the actual time and date of the emissions test so that the Division may have a representative attend.

      [County Rule 270 §404]

   3) The Permittee shall complete and submit a report to the Department within 30 days after completion of the emissions test. The report shall summarize the results of the testing in sufficient detail to allow a compliance determination and demonstration of the appropriate ammonia Molar Ratio value (Permit Condition 22.C) to be made.

      [County Rule 270 §401]

Note: All protocols, notifications and reports required by this permit condition should be addressed to the attention of the Compliance Testing Supervisor.

B. Testing Requirements for the AVEF I and AVEF II Combined Cycle Systems and Auxiliary Boilers:
   The Permittee shall monitor for compliance with the emission limits of Tables 3, 4, 6, 7, 8, 9, 10, 12, and 13 and the HAPs emissions limit of Tables 1 and 2 by conducting stack emissions tests as specified in Table 15.

   [County Rule 210 §302.1(c)(2) and (3)] [locally enforceable only][40 CFR 60.8]

[County Rule 360 §301.1] [40 CFR 60.46a(e) and (g)]

Table 15
AVEF I and II Stack Emissions Test Requirements

Device to be Tested	Pollutant	Method (see Note b)	Frequency
Each Combined Cycle System when Operating with Duct Burners ON and 95% to 105% of full load of the Combined Cycle System	NO_x CO PM_{10} VOC	Method 7e Method 10 Method 5 and 202 Method 25a and 18	Startup and every twelve months thereafter for PM_{10} and VOC, every sixty months thereafter for NO_x and CO
Each Combined Cycle System when Operating with Duct Burners ON and 95% to 105% of full load of the Combined Cycle System	The following HAPs: acetaldehyde, toluene, xylene, ethylbenzene, hexane, formaldehyde	Method 18	One unit from each of AVEF I and AVEF II shall be tested upon startup of AVEF I or II. If annualized total HAPs exceed 2.5 tpy or if any single HAP exceeds 1 tpy from one Turbine and duct burner pair, the additional Turbine and duct burner pair from AVEF I or II shall be tested.
Each Combined Cycle System when Operating with Duct Burners ON and 95% to 105% of full load of the Combined Cycle System	Ammonia	Method specified by the Control Officer	Startup and every sixty months thereafter or, for any individual Combined Cycle System, within ninety days of the ammonia (NH_3) injection rate exceeding the value determined by Permit Condition 22.C in a single Combined Cycle System and sixty months thereafter, whichever is more frequent
Each Combined Cycle System when Operating with Duct Burners OFF and 95% to 105% of full load of the Combustion Turbine	NO_x CO PM_{10} VOC	Method 7e Method 10 Method 5 and 202 Method 25a and 18	Startup and every twelve months thereafter for PM_{10} and VOC, every sixty months thereafter for NO_x and CO; unless all emission limits in Tables 2 and 5 of this Permit are met with Duct Burners ON
Each Combined Cycle System when Operating with Duct Burners OFF and 60% to 80% of full load of the Combustion Turbine	NO_x CO	Method 7e Method 10	Upon Initial Startup
Each Combined Cycle System when Operating with Duct Burners OFF and 60% to 80% of full load of the Combustion Turbine	VOC	Method 25a and 18	Startup and every twelve months thereafter
Each Combined Cycle System when Operating with Duct Burners OFF and 60% to 80% of full load of the Combustion Turbine	PM_{10}	Method 5 and 202	Startup and every twelve months thereafter
Auxiliary Boiler when operating at 95% to 105% of nameplate capacity	NO_x CO PM_{10} VOC	Method 7e Method 10 Method 5 and 202 Method 25a and 18	Startup and every sixty months thereafter

[County Rule 210 §302.1(c)(2) and (3)] [locally enforceable only][40 CFR 60.8]
[County Rule 360 §301.1]

a) For purposes of testing frequency, "startup" for the CTGs is defined as "Within 60 days of achieving maximum production rate on a sustained basis of the Combined Cycle System, but not later than 180 days after actual startup". For the auxiliary boilers, startup is defined as within 60 days of becoming operational, but not later than 180 days after actual startup.

b) "Method" references to 40 CFR Part 60 Appendix A emissions testing methods.

c) Full load is defined as the maximum level of net power output that the CTG or combined cycle system can achieve given the ambient temperature and atmospheric conditions at the site at the time of the source emissions test with inlet air chillers ON.

C. The ammonia (NH_3) injection rate that triggers additional source testing as required in Table 15 shall be determined as follows:

1) The Trigger Rate fro AVEF I is established by the following equation:

Trigger Rate = 29.7 + 1.50*17.034*MR,

Where:

Trigger Rate is pounds ammonia (NH_3) per hour for one AVEF I Combined Cycle System,
29.7 is the pounds of ammonia emitted at 10 ppm ammonia slip,
1.50 is the moles of NO_x to be reacted at full load with Duct Burners ON and 2.5 ppm emission limit,
17.034 is the molecular weight of ammonia, and
MR is the Molar Ratio of NH_3 to NO_x.

2) The Trigger Rate for AVEF II is established by the following equation:

Trigger Rate = 34.0 + 2.12*17.034*MR,

Where:

Trigger Rate is pounds ammonia (NH_3) per hour for one AVEF II Combined Cycle System,
34.0 is the pounds of ammonia emitted at 10 ppm ammonia slip,
2.12 is the moles of NO_x to be reacted at full load with Duct Burners ON and 2.0 ppm emission limit,
17.034 is the molecular weight of ammonia, and
MR is the Molar Ratio of NH_3 to NO_x.

3) A default Molar Ratio (MR) of 1.50 shall be used unless an alternative MR is determined by the Control Officer to be more representative. The initial (upon startup), follow-up stack emissions tests, and/or other emissions monitoring data (whether or not required in Table 15) may be used if acceptable to the Control Officer to determine an alternative MR.

[County Rule 210 §302.1(c)(2) and (3)] [locally enforceable only]

23. OTHER

A. PERMIT SHIELD:

Compliance with the conditions of this Permit shall be deemed compliance with the applicable requirements identified in Appendix B of this Permit. The Permit Shield extends to the non-applicable requirements identified in Appendix C of this permit. The Permit Shield shall not extend to minor permit revisions.

[County Rule 210 §§405.7, 407]

B. COMMENCEMENT OF CONSTRUCTION:

The facility shall commence construction as defined in County Rule 100.200.32 within 18 months of the effective date of this Permit. If construction is not commenced within 18 months, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time, this Permit shall become invalid. The Control Officer shall terminate this Permit if construction is not begun within 18 months or if construction is suspended for more than 18 months.

[40 CFR 52.21(r)(2)][County Rule 240.304.4]

C. ACID RAIN PERMIT:

1) The Acid Rain Phase II Permit Application and Certificate of Representation signed by the Designated Representative on April 17, 2000 and submitted to the Control Officer, shall constitute the Permittee's Acid Rain Permit for AVEF I; and the Acid Rain Phase II Permit Application and Certificate of Representation signed by the Designated Representative on August 29, 2001 and submitted to the Control Officer, shall constitute the Permittee's Acid Rain Permit for AVEF II.
2) The Permittee shall comply with the Acid Rain Permit, 40 CFR Parts 72, 73, and 75, and the Acid Rain requirements of Permit Condition 6.A.
3) The relevant Conditions of this Permit and the Acid Rain Permit, including but not limited to, the Allowable Emission Limits, Operation Requirements, Monitoring/Recordkeeping Requirements, Reporting Requirements, and Testing Requirements shall constitute the Compliance Plan required by 40 CFR Part 72 Subpart D.
4) The Permittee shall hold SO_2 Allowances as of the allowance transfer deadline in each Combined Cycle System compliance subaccount not less than the total annual actual emissions of SO_2 for the previous calendar year from each combined Cycle System as required by the Acid Rain Program.
5) The SO_2 Allowance Allocations and NO_x Requirements for each Combined Cycle System are as follows:

Affected Unit	Pollutant	Years 2000 - 2009	Years 2010 and beyond
CTG 1	SO_2	NA	NA
CTG 1	NO_x	This unit is not subject to a NO_x limit under 40 CFR Part 76	
CTG 2	SO_2	NA	NA
CTG 2	NO_x	This unit is not subject to a NO_x limit under 40 CFR Part 76	
CTG 3	SO_2	NA	NA
CTG 3	NO_x	This unit is not subject to a NO_x limit under 40 CFR Part 76	

CTG 4	SO_2	NA	NA
CTG 4	NO_x	This unit is not subject to a NO_x limit under 40 CFR Part 76	

NA means no Allocations are available since these are new units.

Note that CTG 1 is AVEF I Combined Cycle System No. 1, CTG 2 is AVEF I Combined Cycle System No. 2, CTG 3 is AVEF II Combined Cycle System No. 3, and CTG 4 is AVEF II Combined Cycle System No. 4

[40 CFR 72, 73, and 75]

24. PERMIT CONDITIONS FOR SURFACE COATING OPERATIONS AS SUPPORT ACTIVITIES FOR THIS FACILITY *(Note: This does not include architectural coatings which is covered elsewhere in these permit conditions):*

No surface coating operations other than architectural coatings shall occur at the facility.

25. PERMIT CONDITIONS FOR ARCHITECTURAL COATINGS:

A. Operational Limitations: The Permittee shall not apply any architectural coating manufactured after July 13, 1988, which is recommended for use as a bituminous pavement sealer unless it is an emulsion type coating.

[County Rule 335 §301, SIP Rule 335 §301]

The Permittee shall not apply any non-flat architectural coating manufactured after July 13, 1990, which contains more than 2.1 lbs (250 g/l) of volatile organic compounds per gallon of coating, excluding water and any colorant added to tint bases. These limits do not apply to specialty coatings.

The Permittee shall not apply any architectural coating that exceeds the following limits. Limits are expressed in pounds of VOC per gallon of coating as applied, excluding water and any colorant added to tint bases.

[County Rule 335 §303,305 and SIP Rule 335 §303,305]

SPECIALTY COATINGS:

COATING	(lb/gal)
Concrete Curing Compounds-	2.9
Dry Fog Coating	
Flat-	3.5
Non-flat-	3.3
Enamel Undercoaters-	2.9
General Primers, Sealers and Undercoaters-	2.9
Industrial Maintenance Primers and Topcoats	
Alkyds	3.5
Catalyzed Epoxy	3.5
Bituminous Coating Materials-	3.5
Inorganic Polymers-	3.5
Vinyl Chloride Polymers-	3.5
Chlorinated Rubbers-	3.5
Acrylic Polymers	3.5
Urethane Polymer	3.5

Silicones-	3.5
Unique Vehicles-	3.5
Lacquers-	5.7
Opaque Stains-	2.9
Wood Preservatives-	2.9
Quick Dry Enamels-	3.3
Roof Coatings-	2.5
Semi-transparent Stains-	2.9
Semi-transparent and Clear Wood Preservatives-	2.9
Opaque Wood Preservatives-	2.9
Specialty Flat Products-	3.3
Specialty Primers, Sealers and Undercoaters-	2.9
Stains, All-	2.9
Traffic Coatings	
Applied to Public Streets and Highways	2.1
Applied to other Surfaces	2.1
Black Traffic Coatings	2.1
Varnishes	2.9
Waterproof Mastic Coating-	2.5
Waterproof Sealers-	3.3
Wood Preservatives Except Below Ground	2.9

The Permittee shall not apply any flat architectural coating which contains more than 2.1 lbs (250 g/l) of volatile organic compounds per gallon of coating, excluding water and any colorant added to tint bases. These limits do not apply to specialty coatings.

[County Rule 335 §304, SIP Rule 335 §304]

The following coatings are exempt from the architectural coatings requirements specified in the permit conditions above:

1) Architectural coatings supplied in containers having capacities of one quart or less.
2) Architectural coatings recommended by the manufacturer for use solely as one or more of the following:

    a) Below ground wood preservative coatings.
    b) Bond breakers.
    c) Fire retardant coatings.
    d) Graphic arts coatings (sign paints)
    e) Mastic texture coatings.
    f) Metallic pigmented coatings.
    g) Multi-colored paints.
    h) Quick-dry primers, sealers and undercoaters.
    i) Shellacs.
    j) Swimming pool paints.
    k) Tile-like glaze coatings.

[County Rule 335 §§306, 307 and SIP Rule 335 §§306, 307]

B. Recordkeeping/Monitoring: The Permittee shall keep the material list of all coatings used. The material list should contain the name of each coating, short description of the material, pounds of VOCs per gallon of coating, excluding water and colorant added to tint bases and amount used. If the coating is exempt from the volatile organic compounds content requirements, the justification for the determination shall be documented and kept on file.

[County Rule 210 §302.1.c(2)]

C. Reporting: The Permittee shall file a semiannual compliance report no later than April 30th, and shall report the compliance status of the source during the period between October 1st of the previous year and March 31st of the current year. The second certification shall be submitted no later than October 31st and shall report the compliance status of the source during the period between April 1st and September 30th of the current year. The initial compliance report shall reflect the compliance status of the source beginning with the date of the permit issuance. Compliance report shall include material list and a list of the coatings which are exempt from the volatile organic compounds content requirements.

[County Rule 210 §302.1.d.]

D. Testing: If required by the Control Officer testing procedures to determine compliance with prescribed VOC limits shall be consistent with Reference Methods 24 and 24A in the Arizona Testing Manual for Air Pollutant Emissions.

[County Rule 335 §500 and SIP Rule 335 §500]

26. PERMIT CONDITIONS FOR DUST GENERATING OPERATIONS:

A. Dust Control Plan Required: The Permittee shall submit a Dust Control Plan and obtain the Control Officer's approval of the Dust Control Plan, before commencing any routine dust generating operation. The Dust Control Plan shall include all the information contained in County Rule 310, Section 304 and shall describe all control measures to be implemented before, after, and while conducting any dust generating operation, including during weekends, after work hours, and on holidays. Any control measure that is implemented must meet the applicable standards described in these permit conditions, as determined by the corresponding test method(s), as applicable, and must meet other applicable standards set forth in County Rule 310.

[County Rule 310 §303 and 303.3(b) and SIP Rule 310 §303 and 303.3(b)]]

Failure to comply with the provisions of an approved Dust Control Plan is deemed to be a violation of this Permit. Regardless of whether an approved Dust Control Plan is in place or not, the Permittee is still subject to all requirements of these permit conditions at all times. In addition, the Permittee with an approved Dust Control Plan is still subject to all of the requirements of these permit conditions, even if the Permittee is complying with the approved Dust Control Plan.

[County Rule 310 §306 and SIP Rule 310 §306]

If the Control Officer determines that an approved Dust Control Plan has been followed, yet fugitive dust emissions from any given fugitive dust source still exceed limits from this permit condition, then the Permittee shall make written revisions to the Dust Control Plan and shall submit such revised Dust Control Plan to the Control Officer within three working days of receipt of the Control Officer's written notice, unless such time period is extended by the Control Officer, upon request, for good cause. During the time that the Permittee is preparing revisions to the approved Dust Control Plan, the Permittee must still comply with all requirements of these permit conditions.

[County Rule 310 §305 and SIP Rule 310 §305]

B. Allowable Emissions: The Permittee shall not cause, suffer, allow, or engage in any dust generating or other operation which causes fugitive dust emissions exceeding 20% opacity, even during a wind event (i.e., during wind speeds of 25 mph or greater). Exceedances of the opacity limit that occur due to a wind event shall constitute a violation of the opacity limit. However, it shall be an affirmative defense in an enforcement action if the Permittee demonstrates all of the following conditions:

1) All control measures required were followed and one or more of the control measures listed below were applied and maintained;

a) Cease dust generating operations for the duration of the condition/situation/event when the 60-minute average wind speed is greater than 25 miles per hour. If dust generating operations are ceased for the remainder of the work day, stabilization measures must be implemented; or
b) Apply water or other suitable dust suppressant once per hour; or
c) Apply water as necessary to maintain a soil moisture content at a minimum of 12% as determined by ASTM Method D2216-98 or other equivalent as approved by the Control Officer and the Administer of EPA. For areas which have an optimum moisture content for compaction of less than 12% as determined by ASTM Method D1557-91(1998) or other equivalent as approved by the Control Officer and the Administer of EPA, maintain at least 70% of the optimum soil moisture content.

2) The 20% opacity exceedance could not have been prevented by better application, implementation, operation, or maintenance of control measures;

3) The Permittee compiled and retained records, in accordance with Recordkeeping requirements of this permit; and

4) The occurrence of a wind event on the day(s) in question is documented by records. The occurrence of a wind event must be determined by the nearest Maricopa County Environmental Services Department Air Quality Division monitoring station, from any other certified meteorological station, or by a wind instrument that is calibrated according to manufacturer's standards and that is located at the site being checked.

[County Rule 310 §301, Tables 1 and 2 and SIP Rule 310 §301, Tables 1 and 2]

C. Operational Limitations:

1) Unpaved Access Road: The Permittee shall not allow fugitive dust emissions to exceed 20% opacity from unpaved access roads and:
a) Shall not allow silt loading equal to or greater than 0.33 oz/ft^2; or

b) Shall not allow the silt content to exceed 6%; or

c) As an alternative to meeting the stabilization requirements for an unpaved access road, limit vehicle trips to no more than 20 per day and limit vehicle speeds to no more than 15 miles per hour. If complying with these permit conditions must include, in a Dust Control Plan, the number of vehicles traveled on the unpaved haul/access roads (i.e., number of employee vehicles, earthmoving equipment, haul trucks, and water trucks).

[County Rule 310 §302.2 and SIP Rule 310 §302.2]

2) Open Area Or Disturbed Surface Area: The Permittee on any disturbed surface area on which no activity is occurring shall meet at least one of the standards described below, as applicable. The Permittee shall be considered in violation of this permit if such inactive disturbed surface area is not maintained in a manner that meets at least one of the standards described below, as applicable.

a) Maintain a visible crust; or

b) Maintain a threshold friction velocity (TFV) for disturbed surface areas corrected for non-erodible elements of 100 cm/second or higher; or

c) Maintain a flat vegetative cover (i.e., attached (rooted) vegetation or unattached vegetative debris lying on the surface with a predominant horizontal orientation that is not subject to movement by wind) that is equal to at least 50%; or

d) Maintain a standing vegetative cover (i.e., vegetation that is attached (rooted) with a predominant vertical orientation) that is equal to or greater than 30%; or

e) Maintain a standing vegetative cover (i.e., vegetation that is attached (rooted) with a predominant vertical orientation) that is equal to or greater than 10% and where the threshold friction velocity is equal to or greater than 43 cm/second when corrected for non-erodible elements; or

f) Maintain a percent cover that is equal to or greater than 10% for non-erodible elements; or

g) Comply with a standard of an alternative test method, upon obtaining the written approval from the Control Officer and the Administrator of the Environmental Protection Agency (EPA).

[County Rule 310 §302.3 and SIP Rule 310 §302.3]

3) Weed Abatement By Discing Or Blading: When engaged in weed abatement, the Permittee shall comply with the following work practices. Such work practices shall be implemented to meet the standards described in this permit condition.

a) Apply water before weed abatement by discing or blading occurs; and

b) Apply water while weed abatement by discing or blading is occurring; and

c) Pave, apply gravel, apply water, or apply a suitable dust suppressant, in compliance with these permit conditions, after weed abatement by discing or blading occurs; or

d) Establish vegetative ground cover in sufficient quantity, in compliance with these permit conditions, after weed abatement by discing or blading occurs.

[County Rule 310 §308.8 and SIP Rule 310 §308.8]

4) The Permittee shall not allow or engage in the following on a routine basis:

a) Unpaved parking lots;

b) Vehicle use in open areas;
c) Bulk material transport, hauling, handling and open storage piles;
d) Placement of bulk material onto paved surfaces; and
e) Earthmoving operations on disturbed surface areas one acre or greater. (Earthmoving activities associated with construction may be conducted after a separate earthmoving permit is obtained form the Control Officer)

[County Rule 210 §302.1.b(1)]

D. Recordkeeping/Monitoring:

If the Permittee is required to submit and obtain approval of a Dust Control Plan, the Permittee shall keep a daily written log recording the actual application or implementation of the control measures delineated in the approved Dust Control Plan. The log or the records and supporting documentation shall be made available to the Control Officer within 48 hours, excluding weekends, from written or verbal request.

[County Rule 310 §502 and SIP Rule 310 §502]

Copies of approved Dust Control Plans, control measures implementation records, and all supporting documentation shall be retained at least five years from the date such records are established.

[County Rule 310 §503 and SIP Rule 310 §503]

E. Testing:

The following test methods shall be used as appropriate.

1) Opacity Observations:
   a) Dust Generating Operations: Opacity observations of a source engaging in dust generating operations shall be conducted in accordance with County Rules Appendix C, Section 3 (Visual Determination Of Opacity Of Emissions From Sources For Time-Averaged Regulations) of County Rule 310, except opacity observations for intermittent sources shall require 12 rather than 24 consecutive readings at 15-second intervals for the averaging time.

   [County Rule 310 §501.1(a), County Rules Appendix C Section 3 and SIP Rule 310 §501.1(a), Appendix C Section 3]

   b) Unpaved Access Road: Opacity observations of any unpaved access road shall be conducted in accordance with County Rules Appendix C, Section 2.1 (Test Methods For Stabilization-For Unpaved Roads And Unpaved Parking Lots) of County Rule 310.

   [County Rule 310 §501.1(c), County Rules Appendix C Section 2 and SIP Rule 310 §501.1(c), Appendix C Section 2]

2) Stabilization Observations:
   a) Unpaved Access Road: Stabilization observations for unpaved access roads shall be conducted in accordance with County Rules Appendix C, Section 2.1 (Test Methods For Stabilization-For Unpaved Roads And Unpaved Parking Lots) of County Rule 310. When more than one test method is permitted for a determination, an exceedance of the limits

established in this permit determined by any of the applicable test methods constitutes a violation of these Permit conditions.

[County Rule 310 §501.2(b), County Rules Appendix C Section 2 and SIP Rule 310 §501.2(b), Appendix C Section 2]

b) Open Area Or Disturbed Surface Area: Stabilization observations for an open area and vacant lot or any disturbed surface area on which no activity is occurring (whether at a work site that is under construction, at a work site that is temporarily or permanently inactive) shall be conducted in accordance with at least one of the techniques described in County Rule 310 subsection 501.2(c), as applicable. The Permittee shall be considered in violation of this permit if such inactive disturbed surface area is not maintained in a manner that meets at least one of the standards described in County Rule 310 subsection 302.3, as applicable.

[County Rule 310 §501.2(c) and SIP Rule 310 §501.2(c)]

3) Silt and Soil Moisture Content Methods:

a) ASTM Method C136-96a ("Standard Test Method For Sieve Analysis Of Fine And Coarse Aggregates").

b) ASTM Method D2216-98 ("Standard Test Method For Laboratory Determination Of Water (Moisture) Content Of Soil And Rock By Mass").

c) ASTM Method 1557-91(1998) ("Test Method For Laboratory Compaction Characteristics Of Soil Using Modified Effort (56,000 ft-lb/ft^3 (2,700 kN-m/m^3)").

[County Rule 310 §504 and SIP Rule 310 §504]

27. PERMIT CONDITIONS FOR ABRASIVE BLASTING WITH OR WITHOUT BAGHOUSE:

A. Allowable Emissions: The Permittee shall not discharge into the atmosphere from any abrasive blasting any air contaminant for a period or periods aggregating more than three minutes in any one-hour period which is a shade or density darker than 20 percent opacity.

[County Rule 312 §301] [locally enforceable only]

B. Operational Limitations: The Permittee shall utilize at least one of the following control measures for all abrasive blasting:

1) Confined blasting,
2) Wet abrasive blasting,
3) Hydroblasting,
4) The use of a CARB certified abrasive blasting media is a permissible control measure for use in dry, unconfined blasting operations provided that the following conditions are met:

a) Only an abrasive(s) on the most recent CARB certification list may used in the abrasive blasting process.
b) Blasting is performed only on a metal substrate.
c) The abrasive blasting medium is used only once.
d) The existing paint on the surface to be abraded is lead free (i.e. lead content < 0.1%).
e) Opacity limits of the County Rule 312 are adhered to.
f) The object to be blasted exceeds 8 feet in any dimension or the surface to be blasted is situated at its permanent location.

g) Blasting is not performed at ground level on a surface which may be disturbed by the process and contribute to particulate emissions (e.g. unpaved ground).

[County Rule 312 §302.4][locally enforceable only]

The Permittee shall not forcibly exhaust abrasive blasting equipment to the outside of the building unless the exhaust is vented through a baghouse. The baghouse shall operate within operating parameters specified in Operation and Maintenance (O&M) Plan most recently approved in writing by the Control Officer.

[County Rule 312 §302] [locally enforceable only]

C. Record Keeping: The Permittee shall keep records of the following: following:

1) The dates when abrasive blasting activities are conducted and the type of abrasive material used.
2) Monthly records of the type and amount of abrasive blasting media used.
3) Monthly opacity readings of visible emissions for each month when abrasive blasting is conducted.
4) Opacity reading during the external blasting.
5) Every inspection or preventive maintenance performed on the baghouse according to the Operation and Maintenance Plan. The Permittee shall maintain records of the key system operating parameters required by the O&M Plan. The Permittee shall keep a log demonstrating that any training requirements in the approved O&M Plan are being met.

[County Rules 312 and 210 §302.1.d] [locally enforceable only]

D. Monitoring/Testing: The Permittee shall monitor compliance with the opacity requirements of the permit conditions for abrasive blasting by observations of visible emissions conducted in accordance with EPA Reference Method 9 each time the external blasting is performed and each month the abrasive blasting with baghouse is performed for more than 10 hours.

Visible emission evaluation of abrasive blasting operations shall be conducted in accordance with the following provisions:

1) Emissions from unconfined blasting shall be read at the densest point of the emission after a major portion of the spent abrasives has fallen out, at a point not less than five feet nor more than 25 feet from the impact surface from any single abrasive blasting nozzle.
2) Emissions from unconfined blasting employing multiple nozzles shall be judged as single source unless it can be demonstrated by the Permittee that each nozzle, evaluated separately, meets the emission standards of these Permit Conditions.
3) Emissions from confined blasting shall be read at the densest point after the air contaminant leaves the enclosure.

[County Rules 210 § 302.1.c and 312 §501] [locally enforceable only]

E. Reporting: The Permittee shall file a semiannual compliance report no later than April 30th, and shall report the compliance status of the source during the period between October 1st of the previous year and March 31st of the current year. The second certification shall be submitted no later than October 31st and shall report the compliance status of the source during the period between April 1st and September 30th of the current year. The initial compliance report shall reflect the compliance status of the source beginning with the date of the permit issuance. Compliance report shall include a summary of the opacity readings and date of such readings during external blasting and blasting with baghouse, control measures utilized for abrasive blasting and dates on which any blasting was performed.

[County Rules 312 and 210 § 302.1.e.(1)] [locally enforceable only]

28. PERMIT CONDITIONS FOR THE COLD DEGREASERS AS SUPPORT ACTIVITIES FOR THIS FACILITY:

The Permittee shall not conduct any cold degreasing or other operations subject to County Rule 331 except for wipe cleaning.

29. PERMIT CONDITIONS FOR WIPE CLEANING:

A. Operational Limitations: The Permittee shall conform to the following operating requirements:

1) All solvent storage, including the storage of waste solvent and waste solvent residues, shall at all times be in closed leakfree containers which are legibly labeled with their contents and that are opened only when adding or removing material. Rags used for wipe cleaning shall be stored in closed containers when not in use.

[County Rule 331 §301.1] [SIP Rule 331 §306.3] [SIP Rule 34C.1.(c)]

2) Do not dispose of any solvent, including waste solvent, in such a manner as will cause or allow its evaporation into the atmosphere.

[SIP Rule 331 §306.4] [SIP Rule 34K]

B. Monitoring/Recordkeeping: The Permittee shall:

1) Maintain a current list of solvents; state the VOC content of each in pounds per gallons or grams per liter. The VOC content of solvents and any liquids used as cleaning or degreasing agents shall be stated with water and non-precursors included.

[County Rule 331 §501.1]

2) Maintain monthly records showing the type and amount of each make up solvent added and any other VOC-containing materials used.

[County Rule 331 §501.2(a)], [SIP Rule 331 §501]

3) Monthly visually inspect the facility to ensure that operational limitations of Permit Condition 31.A(1)and (2) are being met.

[County Rule 210 §302.1.c]

4) Records of solvents disposal/recovery shall be kept in accordance with hazardous waste disposal statutes.

[SIP Rule 331 Section 306.4]

C. Reporting: The Permittee shall file a semiannual compliance report starting from this permit issuance date within 30-days of the end of the 6-month period to the Division with attention to Large Sources Compliance Supervisor containing the current list and summary of usage records of the solvents.

[County Rule 210 §302.1.e.(1)] [locally enforceable only]

30. PERMIT CONDITIONS FOR CUTBACK AND EMULSIFIED ASPHALT:

A. Operational Limitations:
The Permittee shall not use or apply the following materials for paving, construction, or maintenance of highways, streets, driveways, parking lots or for any other use to which County Rule 340 §300 and SIP Rule 340 §300 applies:

1) Rapid cure cutback asphalt.
2) Any cutback asphalt material, road oils, or tar which contains more than 0.5 percent by volume VOCs which evaporate at 500^{0}F (260^{0}C) or less using ASTM Test Method D 402-76.
3) Any emulsified asphalt or emulsified tar containing more than 3.0 percent by volume VOCs which evaporate at 500^{0}F (260^{0}C) or less as determined by ASTM Method D 244-89.

[County Rule 340 §301 and SIP Rule 340 §301]

The Permittee shall not store for use any emulsified or cutback asphalt product which contains more than 0.5 percent by volume solvent-VOC unless such material lot includes a designation of solvent-VOC content on data sheet(s) expressed in percent solvent-VOC by volume.

[County Rule 340 §303 and SIP Rule 340 §303]

B. Exemptions: The provisions of these Permit Conditions shall not apply to asphalt that is used solely as a penetrating prime coat and which is not a rapid cure cutback asphalt. Penetrating prime coats do not include dust palliatives or tack coats.

[County Rule 340 §302.1 and SIP Rule 340 §302.1]

The Permittee may use up to 3.0 percent solvent-VOC by volume for batches of asphalt rubber which cannot meet paving specifications by adding heat alone only if request is made to the Control Officer, who shall evaluate such requests on a case-by-case basis. The Permittee shall keep complete records and full information is supplied including savings realized by using discarded tires. The Permittee shall not exceed 1100 lbs (500 kg) usage of solvent-VOC in asphalt rubber in a calendar year unless the Permittee can demonstrate that in the previous 12 months no solvent-VOC has been added to at least 95 percent by weight of all the asphalt rubber binder made by the Permittee or caused to be made for the Permittee. This Permit Condition does not apply to batches which yield 0.5 percent or less solvent-VOC evaporated using the test in County Rule 340 § 502.1.

[County Rule 340 §302.3 and SIP Rule 340 §302.3]

C. Record Keeping: The Permittee shall keep daily records of the amount and type of asphaltic/bituminous material received and used, as well as the solvent-VOC content of this material. Safety data (MSDS) or technical data sheets shall be kept available.

[County Rule 210 §302.1.c][County Rule 340 §501 and SIP Rule 340 §501]

D. Testing Methods:

If required by the Control Officer the applicable testing procedures contained in County Rule 340 §502 and SIP Rule 340 §502 shall be used to determine compliance with these Permit Conditions.

[County Rule 340 §502 and SIP Rule 340 §502]

E. Reporting: The Permittee shall file a semiannual compliance report starting from this permit issuance date within 30-days of the end of the 6-month period to the Division with attention to: Large Sources Compliance Supervisor containing the dates and description of any usage of cutback and emulsified asphalt.

[County Rule 210 §302.1.e.(1)] [locally enforceable only]

31. PERMIT CONDITIONS FOR VOLATILE ORGANIC COMPOUNDS:

No activities subject to County Rule 330 shall occur at the facility.

APPENDIX A

MAJOR EQUIPMENT LIST

Arlington Valley Energy Facility
(AVEF I and AVEF II)

A. AVEF I consists of the following major emitting equipment:

1) Two Combined Cycle Systems (System #1 and System #2) consisting of two Combustion Turbine Generator (CTG)/Heat Recovery Steam Generator (HRSG) trains, and a common reheat condensing steam turbine and electrical generator.

<u>Each</u> CTG/HRSG train consists of the following:

a. General Electric 7FA combustion turbine operating in combined-cycle mode with a nameplate rating of 190 (nominal gross 168) megawatts electric fueled by pipeline quality natural gas only.
b. Supplementary fired, three-pressure Heat Recovery Steam Generator (HRSG) with duct burner. The duct burner has a nameplate rating of 356.6 mmBtu/hr (HHV) and are fueled by pipeline quality natural gas only.
c. Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burners combined to an emission limit equal to or less than 2.5 ppmvd, 3-hour average.
d. Continuous emissions monitor (CEM) system that records at least oxides of nitrogen (NO_x), carbon monoxide (CO), and oxygen (O_2) content of the System exhaust.
e. An exhaust stack with height 185 feet above plant grade and inside diameter of 18 feet.

2) Auxiliary Boiler

a. One 33 mmBtu/hr (HHV, 105% load) auxiliary boiler fueled by natural gas only and exhausting through its own exhaust stack with height 37 feet above plant grade.

3) Wet Cooling Tower

a. One six-cell wet cooling tower, with each cell rated at 23,050 gallons per minute recirculation rate (138,300 gallons per minute total for the cooling tower) and height 47 feet above plant grade.
b. Continuous cooling water conductivity monitoring system.

4) Diesel Engines

a. One 200 horsepower diesel-fueled engine to drive the fire water pump.
b. One 740 horsepower diesel-fueled engine to drive the back-up generator.

B. AVEF II consists of the following major emitting equipment:

1) Two Combined Cycle Systems (System #3 and System #4) consisting of two Combustion Turbine Generator (CTG)/Heat Recovery Steam Generator (HRSG) trains, and a common reheat condensing steam turbine and electrical generator.

<u>Each</u> CTG/HRSG train consists of the following:

a. General Electric 7FA combustion turbine operating in combined-cycle mode with a nameplate rating of 190 (nominal gross 170) megawatts electric fueled by pipeline quality natural gas only.
b. Supplementary fired, three-pressure Heat Recovery Steam Generator (HRSG) with duct burner. The duct burner has a nameplate rating of 594.8 mmBtu/hr (HHV) and is fueled by pipeline quality natural gas only.
c. Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burners combined to an emission limit equal to or less than 2.0 ppmvd, 1-hour average.
d. Catalytic Oxidizer (CAT-OX) carbon monoxide and volatile organic emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burners combined to a CO emission limit equal to or less than 3.0 ppmvd, 3-hour average with duct burners ON and 2.0 ppmvd, 3-hour average with duct burners OFF; and VOC concentration less than 4.0 ppmvd with duct burners ON and 1.0 ppmvd with duct burners OFF.
d. Continuous emissions monitor (CEM) system that records at least oxides of nitrogen (NO_x), carbon monoxide (CO), and oxygen (O_2) content of the System exhaust.
e. An exhaust stack with height 185 feet above plant grade and inside diameter of 19 feet.

2) Auxiliary Boiler

a. One 33 mmBtu/hr (HHV, 105% load) auxiliary boiler fueled by natural gas only and exhausting through its own exhaust stack with height 32 feet above plant grade.

3) Wet Cooling Tower

a. One six-cell wet cooling tower, with each cell rated at 22,500 gallons per minute recirculation rate (180,000 gallons per minute total for the cooling tower) and height 48 feet above plant grade.
b. Continuous cooling water conductivity monitoring system.

4) Diesel Engines

a. One 200 horsepower diesel-fueled engine to drive the fire water pump.
b. One 740 horsepower diesel-fueled engine to drive the back-up generator.

APPENDIX B

PERMIT SHIELD APPLICABLE REQUIREMENTS

Arlington Valley Energy Facility

(AVEF I and II)

Identified below are all federal, state and local air pollution control requirements applicable to the Permittee at the time the permit is issued. Compliance with the conditions of the permit shall be deemed compliance with any applicable requirements as of the date of permit issuance included in the Appendix B "Permit Shield" of this permit.

For each part, subpart, section, and subsection reference listed, all subsequent sections are assumed applicable. All other subparts or sections not listed are not applicable.

County Requirements

Maricopa County
Air Pollution Control Regulations

Regulation I General Provisions

Rule 100		**General Provisions and Definitions (11/6/02 revision)**
	§104	Circumvention
	§105	Right of Inspection of Premises
	§106	Right of Inspection of Records
	§ 301	Air Pollution Prohibited
	§ 501	Reporting Requirements
	§ 502	Data Reporting
	§ 503	Emission Statements Required as Stated in the Act
	§ 504	Retention of Records
	§ 505	Annual Emissions Inventory Report

Rule 130		**Emergency Provisions (7/26/00 revision)**
	§400	Administrative Requirements

Rule 140		**Excess Emissions (9/5/01 revision)**
	§400	Administrative Requirements
	§500	Monitoring and Records

Regulation II Permits and Fee

Rule 200		**Permit Requirements (8/22/01 revision)**
	§ 301	Permits Required
	§ 302	Title V Permit
	§ 305	Earth Moving Permit
	§ 306	Permit to Burn
	§ 310	Prohibition – Permit Modification
	§ 311	Permit Posting Required

Rule 210		**Title V Permit Provisions (12/19/01 revision)**
	§ 402	Permit Term
	§ 403	Source Changes Allowed without Permit Revisions
	§ 404	Administrative Permit Revisions
	§ 405	Minor Permit Revisions
	§ 406	Significant Permit Revisions
	§ 407	Permit Shields

Rule 241		**Title V Permit Provisions (6/19/96 revision)**
	§ 301	Best Available Control Technology (BACT) Required
	§ 303	Circumvention

Rule 270		**Performance Tests (11/15/93 revision)**
	§ 301	Performance Tests Required (approved test methods)
	§301.1	Applicable Procedures and Testing Methods
	§ 301.2	Opacity determined by Reference Method 9 of the AZ Testing Manual
	§ 401	Performance Tests Required
	§ 402	Testing Criteria
	§ 403	Testing Conditions
	§ 404	Notice of Testing
	§ 405	Testing Facilities Provided
	§ 406	Minimum Testing Required

Rule 270		**Performance Tests (11/15/93 revision)**
	§ 407	Compliance with the Emission Limits
	§ 408	Additional Testing

Regulation III Control of Air Contaminants

Rule 300		**Visible Emissions (2/7/01 revision)**
	§ 301	Limitations – Opacity/General: Opacity $\leq$ 20%
	§ 501	Compliance Determination – Opacity
	§ 502	Compliance Determination – Opacity of Visible Emissions from Intermittent Sources

Rule 310		**Open Fugitive Dust Sources (2/16/00 revision)**
	§ 301	Opacity Limitation for Fugitive Dust Sources
	§302	Stabilization Requirements for Fugitive Dust Sources
	§ 303	Dust Control Plan Required
	§ 304	Elements of a Dust Control Plan
	§ 305	Dust Control Plan Revisions
	§ 306	Control Measures
	§ 308	Work Practices
	§ 401	Dust Control Plan Posting
	§ 501	Compliance Determination
	§ 502	Recordkeeping
	§ 503	Records Retention
	§ 504	Test Methods Adopted by Reference
	Table 1	Source Type and Control Measures
	Table 2	Source Type and Wind Event Control Measures

Rule 312		**Abrasive Blasting (7/13/88 revision)**
	§ 301	Limitations
	§ 302	Controls Required
	§ 501	Visible Emission Evaluation Techniques

Rule 320		**Odors and Gaseous Air Contaminants (7/13/88 revision)**
	§ 300	Standards
	§ 302	Material Containment Required
	§ 304	Limitation – Hydrogen Sulfide

Rule 331		**Solvent Cleaning (4/7/99 revision)**
	§ 301	Solvent Handling Requirements
	§ 501	Recordkeeping and Reporting

Rule 335		**Architectural Coatings (7/13/88 revision)**
	§ 301	Prohibition – Bituminous Pavement Sealers
	§ 303	Final Limits – Non-Flat Architectural Coatings
	§ 304	Limits – Flat Architectural Coatings
	§ 305	Limits – Specialty Coating

Rule 340		**Cutback and Emulsified Asphalt (9/21/92 revision)**
	§ 301	Limitations
	§ 501	Recordkeeping and Reporting

Rule 360		**New Source Performance Standards (3/7/01 revision)**
	§ 301	Adopted Federal Standards
	§ 301	Subpart A – General Provisions
	§ 301	Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978
	§ 301	Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
	§ 301	Subpart GG – Standard of Performance for Stationary Gas Turbines

Rule 371		**Acid Rain (3/7/01 revision)**

	§ 301	Incorporated Subparts of the Federal Acid Rain Regulations

Regulation VI **Emergency Episodes**

Rule 600		**Emergency Episodes (7/13/88 revision)**
	§ 302	Control Actions

Appendices

Appendix C		**(2/16/00 revision)**
	Section 2	Test Methods for Stabilization
	Section 3	Visual Determination of Opacity of Emissions from Sources for the Time-Averaged Regulations

State Requirements
Arizona Administrative Code
(Applicable in Maricopa County; ARS § 49-106)

R18-2-719.C.1 (R9-3-519.C.1)	For stationary rotating machinery having a heat input rate of 4200 million BTU per hour or less, the maximum allowable particulate emissions rate in pounds-mass per hour $E = 1.02Q^{0.769}$ where: Q = heat input in million BTU per hour.

This provision is applicable only to the diesel fire pump engine and the back-up generator. The other fuel burning equipment (Combined Cycle Systems, auxiliary boiler) are not “existing” equipment since a New Source Performance Standard applies (definition of “existing source”, R18-2-101.38).

Federal Requirements

New Source Performance Standards General Provisions (40 CFR Part 60 Subpart A)

§ 60.4(a), (b), (D)	Address
§ 60.7(a), (b), (c), (d),(f)	Notification and Recordkeeping
§ 60.8	Performance Tests
§ 60.12	Circumvention
§ 60.13	Monitoring
§ 60.19	General Notification and Reporting Requirements

New Source Performance Standards – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (40 CFR Part 60 Subpart Da)

§ 60.42a	Standard for Particulate Matter
§ 60.43a(b), (g)	Standard for Sulfur Dioxide
§ 60.44a(a), (d1)	Standard for Nitrogen Oxides
§ 60.46a	Compliance Provisions
§ 60.47a(c) through (k)	Emission Monitoring
§ 60.48a	Compliance Demonstration Procedures and Methods
§ 60.49a	Reporting Requirements

New Source Performance Standards – Standards of Performance for Small Industrial — Commercial—Institutional Steam Generating Units (40 CFR Part 60 Subpart Dc)

§ 60.48c(a), (g), and (i)	Reporting and Recordkeeping Requirements

New Source Performance Standards – Standards of Performance for Stationary Gas Turbines (40 CFR Part 60 Subpart GG)

§ 60.332(a) and (b)	Standard for Nitrogen Oxides

§ 60.333	Standard for Sulfur Dioxide
§ 60.334(b)	Monitoring of Operations
§ 60.335	Test Methods and Procedures

NESHAP Program (40 CFR Part 61)

Subpart M National Emission Standard for Asbestos	
§ 61.145(a)(2)	Standard for demolition and renovation
§ 61.145(b)(1), (2), (3)(i) and (3)(iv), (4)(i) through (vii) and (4)(ix) and (4)(xvi)	Notification requirements when demolishment involves less than 80 linear meters on pipes and less than 15 square meters on other services and less than one cubic meter off facility components of regulated asbestos containing material (RACM) where the length or area could not be measured previously or there is no asbestos.

Accidental Release Program (40 CFR Part 68)

§ 112(r)(1)	General duty to identify, prevent and minimize the consequences of accidental releases of listed and other extremely hazardous substances.
Part 68	Chemical Accident Prevention Provisions

Permits Regulation (40 CFR Part 72)

Subpart A provisions	**Acid Rain Program General Provisions**
72.9(a), (b), (c), (d), (f), (g)4	Standard Requirements
Subpart B	**Designated Representative**
72.20	Authorizations and Responsibilities of the Designated Representative
72.21	Submissions
72.22	Alternate Designated Representative
72.23	Changing the Designated Representative
Subpart C	**Acid Rain Permit Applications**
72.30(a), (b)(2)(ii), (d)	Requirements to Apply
Subpart D	**Acid Rain Compliance Plan and Compliance Options**
72.40(a)(1)	General, Compliance Plan with sulfur dioxide emissions

Subpart I	**Compliance Certification**
72.90	Annual Compliance Certification Report
72.95	Allowance Deduction Formula
Appendix A	**Methodology for Annualization of Emissions Limits**
Appendix B	**Methodology for Conversion of Emissions Limits**
Appendix D	**Calculation of Potential Electric Output Capacity**

Sulfur Dioxide Allowance System (40 CFR Part 73)

Subpart B	**Allowance Allocations**
73.33(a), (c)	Authorized Account Representative
Subpart D	**Allowance Transfer**
73.50(b)	Scope and Submission of Transfers

Continuous Emission Monitoring (40 CFR Part 75)

Subpart A	**General**
75.4(b)(2),(c)(2),(i)(2)	Compliance Dates
Subpart B	**Monitoring Provisions**
75.10	General Operating Requirements
75.11(d)(2)	Specific Provisions for Monitoring SO_2 Emissions
75.12(a),(b),(c)	Specific Provisions for Monitoring NO_x Emissions
75.13(b)	Specific Provisions for Monitoring CO_2 Emissions
75.16(b),(e)	Special Provisions for Monitoring Emissions from Common, Bypass, and Multiple Stacks for SO_2 Emissions and Heat Input Determinations
Subpart C	**Operation and Maintenance Requirements**
75.20	Certification and Recertification Procedures
75.21	Quality Assurance and Quality Control Requirements
75.22	Reference Test Methods
75.24	Out-of-Control Periods and Adjustments for System Bias
Subpart D	**Missing Data Substitution Procedures**

75.30	General Provisions
75.31	Initial Missing Data Procedures
75.32	Determination of Monitor Data Availability for Standard missing Data Procedures
75.33	Standard Missing Data Procedures for SO_2, NO_x, and Flow Rate
75.34	Units with Add-on Emission Controls
75.35	Missing Data Procedures for CO_2 Data
75.36	Missing Data Procedures for Heat Input Determinations
Subpart E	**Alternative Monitoring Systems**
75.40	General Demonstration Requirements
75.41	Precision Criteria
75.42	Reliability Criteria
75.43	Accessibility Criteria
75.44	Timeliness Criteria
75.45	Daily Quality Assurance Criteria
75.46	Missing Data Substitution Criteria
75.47	Criteria for a Class of Affected Units
75.48	Petition for an Alternate Monitoring System
Subpart F	**Recordkeeping Requirements**
75.53(a), (b), (f)(1), (f)(4), (f)(6)	Monitoring Plan
75.57	General Recordkeeping Provisions
75.58(b), (c)	General Recordkeeping Provisions for Specific Situations
75.59	Certification, Quality Assurance, and Quality Control Record Provisions
Subpart G	**Reporting Requirements**
75.60	General Provisions
75.61	Notifications
75.62	Monitoring Plan Submittals
75.63	Initial Certification or Recertification Application Submittals
75.64	Quarterly Reports

Subpart H	**NO_x Mass Emissions Provisions**
Appendix A	**Specifications and Test Procedures**
Appendix B	**Quality Assurance and Quality Control Procedures**
Appendix F	**Conversion Procedures**
Appendix G	**Determination of CO_2 Procedures**

Protection of Stratospheric Ozone (40 CFR Part 82)

Subpart F	**Recycling and Emissions Reduction**
§ 82.161	Technician Certification
§ 82.166	Reporting and Recordkeeping

Subpart G	**Significant New Alternatives Policy Program**
§ 82.174(b)	Prohibition against use of substitute
§ 82.174(c)	Prohibition against use of substitute without adhering to use restrictions
§ 82.174(d)	Prohibition against use of substitute after added to list of unacceptable substitutes

Federal Requirements

Maricopa County State Implementation Plan (as of 10/01/00)

Regulation I General Provisions

Rule 3 Air Pollution Prohibited

Regulation II Permits

Rule 22 – Permit Denial – Action – Transfer – Posting – Revocation – Compliance
§F – Permit Posting
Rule 27 - Performance Tests

Regulation III Control of Air Contaminants

Rule 30 - Visible Emissions
Rule 31 - Emissions of Particulate Matter
§§ A.1,2,3,4,6,7, - Non-Point Sources of Particulate Matter.
§ H.1.a - Fuel Burning
Rule 32 - Odors and Gaseous Emissions
§§ A, C, E, F
Rule 34 – Organic Solvents – Volatile Organic Compounds
§ C.1 – Metal cleaning operations
§ K – Limits on Photochemically Reactive Solvent
Rule 310 – Fugitive Dust Sources
Rule 335 – Architectural Coatings
Rule 340 – Cutback and Emulsified Asphalt
§§ 301, 501

Rule IV Production of Records: Monitoring, Testing and Sampling Facilities

Rule 40	**Recordkeeping and Reporting**
Rule 41 § A	**Monitoring**
Rule 42	**Testing and Sampling**
Rule 43	**Right of Inspection**

Regulation VII Ambient Air Quality Standards

Rule 72	**Emergency Episode Criteria**
§72e	Air Pollution Alert Actions
§72f	Air Pollution Warning Actions
§72g	Air Pollution Emergency Actions

APPENDIX C

PERMIT SHIELD NON-APPLICABLE REQUIREMENTS

Arlington Valley Energy Facility

(AVEF I and AVEF II)

Identified below are *some* of the federal, state and local air pollution control requirements that do NOT apply to the Permittee at the time the permit is issued because the operations subject to these rules will not occur at AVEF I and II. The list is not all inclusive and there may be additional requirements that do not apply but are not listed in this Appendix C of this permit.

Federal Rules Not Applicable to AVEF I and II

CAA Section 112(g)	**Case by Case MACT**
40 CFR Part 63	**NESHAPs for Major Sources of HAPs**
40 CFR 60 Subpart D	**Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971**
40 CFR 60 Subpart Db	**Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**
40 CFR 64	**Compliance Assurance Monitoring**
40 CFR 75.17	**Affected Units Exhausting through a Common Stack**

County and Federally Enforceable SIP Rules Not Applicable to AVEF I and II

Rule 34(E)(1)	**Non-architectural spray paint operations**
Rule 310, Sections 302.1, 302.4, 308.1, 308.2, 308.3, 308.6, 308.7	**Certain material handling and other dust generating activities that will not occur at AVEF I and II on a routine basis**
Rules 330 and 331, Sections 302-309	**Solvent cleaning machines**
Rules 50 and 314	**Open Outdoor Fires**

APPENDIX D

MONITORING NO_X COMPLIANCE BY AMMONIA INJECTION RATE MONITORING For AVEF I

To ensure that the SCR system for AVEF I is properly operated to achieve the design control rate of 2.5 ppm NO_x, the owner/operator shall monitor and achieve a minimum ammonia injection rate for the first two years of commercial operation. Once this two year period is completed and the final NO_x emission limit is determined, the “minimum ammonia injection rate” requirement shall be no longer be effective. The minimum ammonia injection rate to achieve 2.5 ppm controlled levels shall be calculated as follows:

Step 1 – Calculate the required NO_x Removal:

This calculation uses the actual measured NO_x concentration at the turbine outlet (i.e., before the SCR system) and the target control level of 2.5 ppm to determine the amount of NO_x that must be removed. The actual turbine outlet NO_x concentration is used because the turbine emissions can vary, and so the amount of NO_x that must be removed also varies. From Equation F-5 in 40 CFR 75 (for converting from ppm to lb/MMBTU):

NO_x = [1.194 x 10^{-7} (lb/scf)/ppm] [X-2.5 ppm] [8,710 scf/MMBTU] [(20.9%)/(20.9% - 15%O_2)]

where:

X = ppmv NO_x in turbine outlet to SCR

Flue gas is standardized to 15% O_2 for combustion turbine

Simplifying this equation results in :

NO_x to be removed = (0.00368 X - 0.00921) lb/MMBTU NO_x

Step 2 – Calculate the required NH_3 injection rate:

Since 1 mole of NH_3 reacts with one mole of NO, but 2 moles of NH_3 react with one mole of NO_2, the equation uses the relative molecular weights of NH_3 versus NO to calculate the required NH_3 injection rate in units of lb/MMBTU. (Since the ratio of NO_2 to NO is probably less than 0.5, using a molar ratio other than 1.0 would overestimate the minimum required NH_3 injection rate). The minimum rate is, therefore:

NH_3 = [(0.00368 X - 0.00921) lb/MMBTU NO_x] (17 NH_3/46 NO_x)
= (0.00136 X - 0.00340) lb/MMBTU NH_3

Example

If the measured turbine outlet NO_x at full load without duct burners is equal to the manufacturers guarantee of 9 ppm, then the required NH3 injection rates is

NH_3 = (0.00136 * 9) – 0.00340 = 0.00884 lb/MMBTU

Step 3 –Calculate the ammonia usage and verify compliance with the required NH_3 injection rate:

When the source and type of ammonia is determined (i.e., anhydrous versus aqueous solution at some specified concentration level), the following equation will be used to verify compliance with the required ammonia injection rate:

NH3 injected (lb) = gallons of NH3 solution used (gal) * density of liquid (lb/gal) * equivalent concentration of NH3 by weight (lb NH3/lb solution)

Step 4 – Compliance Averaging Interval

The daily average (i.e., 24-hour block average) turbine outlet NO_x concentration during periods of normal operation (Mode 6) will be measured and reported. The daily ammonia consumption during the same time periods of normal operations will also be measured and reported. The above equations will be used to demonstrate compliance with the required ammonia injection rate on a daily basis.

END OF PERMIT

Technical Support Document
Arlington Valley Energy Facility (AVEF I and AVEF II)
Prevention of Significant Deterioration,
Title IV, and Title V Permit Number V99-014,
Minor Modification Number 9-06-01-01, and
Significant Revision Number S01-004.

I. APPLICANT

Duke Energy Arlington Valley, LLC
5400 Westheimer Court
Houston, TX 77056

II. PROJECT LOCATION

Duke Energy Arlington Valley ("Duke") was permitted on November 28, 2000 to construct and operate the Arlington Valley Energy Facility I (AVEF I) located on a 40-acre site one mile west of the intersection of 383rd Avenue and Elliott Road, Arlington, Arizona in Maricopa County. Duke has requested, and this Technical Support Document supports, a Significant Permit Revision to add a second generating unit, Arlington Valley Energy Facility II (AVEF II) at the same site. AVEF I and II are located on Section 17/Township 1 South/Range 6 West at 112^{o} 53' 28'' West longitude and 33^{o} 20' 25" North latitude. The site elevation is 881 feet above mean sea level (msl). The northwest corner of the site is at UTM 323,852.0 East and 3,690,212.0 North. The site location is near (approximately 3.5 miles southwest) of the existing Palo Verde Nuclear Generating Station (PVNGS).

AVEF I is a natural gas fired combined cycle merchant power plant with two combustion turbine generators (CTGs) and one steam turbine generator (STG). Each CTG has a gross nominal output of 168 megawatts electric (MWe), the STG has a gross nominal output of 244 MWe when duct firing, resulting in a gross nominal output at AVEF I of 580 MWe. AVEF II is a proposed new natural gas fired combined cycle merchant power plant with two CTGs and one STG. Each CTG has a gross nominal output of 170 MWe, the STG has a gross nominal output of 310 MWe when duct firing, resulting in a gross nominal output at AVEF II of 650 MWe. Together, AVEF I and II will produce a gross nominal output of 1,230 MWe. AVEF I and II are owned and operated by Duke Energy Arlington Valley, LLC. The project is classified as Standard Industrial Classification (SIC Code) 4911 and North American Industrial Classification System (NAICS) 221112, Fossil-Fuel Electric Power Generation.

With respect to the National Ambient Air Quality Standards (NAAQS), portions of Maricopa County are designated as serious nonattainment for PM_{10}, CO, and ozone (since the 182(f) waiver is not implemented in Maricopa County for New Source Review purposes, both of the precursor pollutants NO_x and VOC are regulated by the County for ozone NAAQS purposes). The County is designated as attainment/unclassified for SO_2, NO_2, and lead. However, the site is located in an attainment area considerably west of the nonattainment area boundaries (about 15 miles to the west of the PM_{10} nonattainment boundary, and 25 miles west of the CO and ozone nonattainment boundary).

The Maricopa County Environmental Services Department (MCESD) has been delegated primary responsibility for the Prevention of Significant Deterioration (PSD) program in the County, and therefore, the project comes under the jurisdiction of MCESD. Since the addition of AVEF II is a major modification to a PSD source, it comes under PSD, Title IV and Title V regulatory programs.

III. PROJECT DESCRIPTION

Duke initially filed a combined PSD and Title V Air Quality Permit Application for the AVEF I project in October 1999, and submitted a supplement to the Application on April 21, 2000 to include the Title IV Permit Application and to reflect changes and corrections to the original application. The application was submitted pursuant to MCESD Rules 200, 210 and 240. AVEF I was issued a combined Title IV, Title V, and PSD permit on November 28, 2000. Duke submitted an application for a minor revision for AVEF I (9-06-01-01) to support the following changes:

1) Change the cooling tower from a ten-cell to a six-cell tower, change the water circulation rate (from 144,243 gallons per minute to 138,300 gallons per minute, change the exhaust flow rate (from 613 cubic meters per second to 728 cubic meters per second), and slightly change the emissions (from 4.33 pounds per hour to 4.15 pounds per hour).
2) Slightly change the auxiliary boiler exhaust temperature (temperature from 450 degrees F to 385 degrees F) and exhaust flow rate (from 6630 cfm to 6035 cfm), but leave the emissions unchanged.
3) Slightly change the location of the turbine stacks, cooling towers, and auxiliary boiler stack to reflect current final design (move the turbines about 3 meters north-northeast, move the cooling towers about 19 meters northeast and move the auxiliary boiler about 94 meters southeast).
4) Change the horsepower ratings of the emergency fire pump diesel engine and the backup generator diesel engine from 400 hp and 805 hp to 200 and 740 hp, respectively.

MCESD issued the AVEF I minor revision in February 2002.

The Significant Revision application to add AVEF II was initially submitted in September, 2001. A BACT Addendum was filed in January, 2002, and the application was further modified in April 2002 with additional LAER requirements required by the Arizona Corporation Commission. Then in November 2002, Duke submitted a complete revised application to reflect a slight increase in size of AVEF II (from nominal rating of 620 MW to 650 MW).

A draft permit was issued for a 30 day public review on April 16, 2003. No comments were received from the public. After the public comment period closed, the draft permit was provided to the USEPA for review. During the 45 day review period, USEPA indicated that the BACT limit of 2.5 ppm, 1 hour average for NO_x should be reduced to 2.0 ppm, 3 hour average for NO_x, and the BACT limit of 4.0 ppm, 3 hour average for CO should be reduced to 3.0 ppm, 3 hour average for CO. Duke submitted additional information on May 21 and July 3, 2003 that the NOx level has not been demonstrated in practice at any similar facility with duct burners and not during transient hours. USEPA rejected Duke's request for reconsideration with respect to this and previously submitted information. Based on USEPA's comments, the permit was revised to reflect the 2.0 ppm, 3-hour average NO_x limit during the initial two year demonstration period, and the 3.0 ppm, 3-hr average for CO. After the demonstration period, the limit will be reduced to 2.0 ppm, 1-hour NOx limit unless the Duke can demonstrate why this level is infeasible. MCESD sent the revised permit to EPA on September 17, 2003 for signature, wherein the permitted NOx limit after the end of the demonstration period could be more than 2.0 ppm, 1-hour if justified, but only up to the emissions level analyzed by MCESD and reviewed by the public. EPA provided comments on October 14 that this limit was not acceptable, and had to reflect a revised limit of no more than 2.0 ppm, 3-hour average. Duke agreed to accept this limit for AVEF II as long as their concern regarding the lack of demonstration of this limit on a duct fired power plant was documented. This Technical Support Document has been updated to reflect this revision in Tables 4-1 through 4-17 as applicable. However, the discussions of air quality impacts in Sections VII, IX, X, and XII are based on 2.5 ppm NO_x and 3.0 ppm CO.

The major AVEF I components with the potential for air quality emissions are listed in Table 3-1 (including the changes submitted as part of the minor modification). AVEF I includes two General

Electric 7FA natural gas-fired combustion turbine generators (CTGs) operating in combined-cycle mode with two supplementary fired, three pressure Heat Recovery Steam Generators (HRSGs) and a common, reheat condensing steam turbine. Steam generation in each of the HRSGs is augmented with a supplementary natural gas fired duct burner. Each HRSG is also outfitted with a Selective Catalytic Reduction (SCR) system to reduce the emissions of NO_x by approximately 70%.

AVEF II will consist of essentially the same equipment as AVEF I except that AVEF II units are slightly larger and AVEF II will also include a catalytic oxidizer (CAT-OX) for reduction of CO, VOCs, and HAPs. The major AVEF II components are shown in Table 3-2.

Table 3-1
AVEF I Major Emitting Equipment

Two Combined Cycle Systems (System #1 and System #2) consisting of two Combustion Turbine Generator (CTG)/Heat Recovery Steam Generator (HRSG) trains and a common reheat condensing steam turbine and electrical generator.	
	Each CTG/HRSG train consists of the following:
a.	General Electric 7FA CTGs operating in combined-cycle mode with a nameplate rating of 190 (gross nominal output of 168) megawatts electric each fueled by pipeline quality natural gas only.
b.	Supplementary fired, three-pressure Heat Recovery Steam Generator (HRSG) with duct burners. Each duct burner has a nameplate rating of 356.6 mmBtu/hr (HHV) and is fueled by pipeline quality natural gas only.
c.	Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burners combined.
d.	Continuous emissions monitor (CEM) system that records at least oxides of nitrogen (NO_x), carbon monoxide (CO), and oxygen (O_2) content of the Combined Cycle System exhaust.
e.	An exhaust stack with height 185 feet above plant grade and inside diameter of 19 feet
Auxiliary Boiler	
a.	One 33 mmBtu/hr (HHV at 105% load) auxiliary boiler fueled by natural gas only and exhausting through its own exhaust stack with height 32 feet above plant grade.
Wet Cooling Tower	
a.	One six-cell wet cooling tower, with each cell rated at 23,050 gallons per minute recirculation rate (138,300 gallons per minute total for the cooling tower) and height 48 feet above plant grade.
b.	Continuous cooling water conductivity monitoring system
Emergency Diesel Engines	
a.	One 200 horsepower diesel-fueled engine to drive the emergency fire water pump
b.	One 750 horsepower diesel-fueled engine to drive the back-up generator (500 kW).

Table 3-2
AVEF II Major Emitting Equipment

Two Combined Cycle Systems (System #3 and System #4) consisting of two Combustion Turbine Generator (CTG)/Heat Recovery Steam Generator (HRSG) trains and a common reheat condensing steam turbine and electrical generator.	
	Each CTG/HRSG train consists of the following:
a.	General Electric 7FA CTGs operating in combined-cycle mode with a nameplate rating of 190 (gross nominal output of 170) megawatts electric fueled by pipeline quality natural gas only.
b.	Supplementary fired, three-pressure Heat Recovery Steam Generator (HRSG) with duct burners. Each duct burner has a nameplate rating of 670 mmBtu/hr (HHV) and is fueled by pipeline quality natural gas only.
c.	Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burners combined.
d.	Catalytic Oxidizer (CAT-OX) carbon monoxide and volatile organic emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burners combined.
e.	Continuous emissions monitor (CEM) system that records at least oxides of nitrogen (NO_x), carbon monoxide (CO), and oxygen (O_2) content of the Combined Cycle System exhaust.

f.	An exhaust stack with height 185 feet above plant grade and inside diameter of 18 feet
Auxiliary Boiler	
a.	One 33 mmBtu/hr (HHV at 105% load) auxiliary boiler fueled by natural gas only and exhausting through its own exhaust stack with height 37 feet above plant grade.
Wet Cooling Tower	
a.	One eight-cell wet cooling tower, with each cell rated at 22,500 gallons per minute recirculation rate (180,000 gallons per minute total for the cooling tower) and height 47 feet above plant grade.
b.	Continuous cooling water conductivity monitoring system
Emergency Diesel Engines	
a.	One 200 horsepower diesel-fueled engine to drive the emergency fire water pump
b.	One 750 horsepower diesel-fueled engine to drive the back-up generator (500 kW).

For some emission calculations and permit limits involving emissions in terms of heat input rate (e.g., pounds per million Btu), the heat input rate in terms of million Btu per hour (mmBtu/hr) is required. The heat input rate is a function of the heat content of the fuel (e.g., higher heating value or lower heating value), and the temperature and load conditions, among other variables. For purposes of assessing emissions in terms of mmBtu, a higher heating value (HHV) of 1020 Btu per standard cubic foot of natural gas has been assumed. Using this heating value and the amount of natural gas that will be combusted in the Combustion Turbines during 100% load and 66.3 degrees Fahrenheit (annual average temperature at the site), the AVEF I Combustion Turbines will each combust approximately 1,737 mmBtu/hr at full load. Likewise, at full load the AVEF I duct burners will combust approximately 357 mmBtu/hr. The AVEF II Combustion Turbines will each combust approximately 1,756 mmBtu/hr (HHV) and the AVEF II duct burners will combust approximately 670 mmBtu/hr (HHV) at full load.

The combustion turbines have a "nameplate" rating as well as a "nominal" output rating. The nameplate rating occurs only under a specific set of atmospheric conditions (temperature, pressure, etc.) that cannot occur at the Arlington Valley location (due to altitude above sea level and high temperatures). Therefore, the units have a "nominal" rating as well as a nameplate rating, and the nominal rating is the most relevant. In addition, "full load" is a time and site-specific parameter based on the atmospheric conditions at the time the unit is running. "Full load" will be different than "nominal" and certainly different than "nameplate" rating.

On the other hand, boilers have a "nameplate rating" that is achievable at Arlington Valley. Both the AVEF I and II auxiliary boilers have a nameplate rating of 33 mmBtu/hr (HHV), at 105% load and that value will be used for hourly emission calculations.

IV. EMISSIONS FROM AVEF I and AVEF II

AVEF I has a single set of emission limits that are both federally and locally enforceable, based on Best Available Control Technology (BACT). However, AVEF II has a dual set of emission limits. One set of emission limits is federally enforceable and is based on BACT. The other set of emission limits is voluntarily accepted, locally enforceable only, and has been determined to be equivalent to lowest achievable emission rate levels by MCESD. Therefore, in the following discussion, there is a dual set of tables, one set based on AVEF II at the federally enforceable BACT levels and the other at the voluntarily accepted, locally enforceable levels.

A. Combined Emissions from AVEF I and AVEF II

Tables 4-1 and 4-2 display the facility total emissions from both AVEF I and AVEF II. However, AVEF I and II have individual emission limits. The totals in Tables 4-1 and 4-2 are shown for reference only, and the details for the individual emitting units are shown in the tables following. The notes for the tables are shown following Tables 4-7 and 4-14.

Table 4-1
AVEF I plus AVEF II Annual Emissions with AVEF II at BACT

	Rolling 12-month Total Emission Limits (tons per year)				
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**
Total of Four Combined Cycle Systems	93.0	444.6 Note 1	1,416.6	407.8	242.6
Two Auxiliary Boilers	0.4	6.6	28.2	1.8	3.0
Two Cooling Towers	NA	NA	NA	19.0	NA
TOTAL for AVEF I and II	**93.4**	**451.2 Note 1**	**1,444.8**	**428.6**	**245.6**

Table 4-2
AVEF I plus AVEF II Annual Emissions with AVEF II Locally Enforceable Limits

	Rolling 12-month Total Emission Limits (tons per year)				
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**
Total of Four Combined Cycle Systems	93.0	444.6 Note 1	1,375.0	358.0	195.0
Two Auxiliary Boilers	0.4	6.6	28.2	1.8	3.0
Two Cooling Towers	NA	NA	NA	19.0	NA
TOTAL for AVEF I and II	**93.4**	**451.2 Note 1**	**1,403.2**	**378.8**	**198.0**

B. Emissions from AVEF I

Tables 4-3 through 4-8 display the maximum permit limits (potential to emit, or PTE) with pollution controls from the AVEF I systems for the criteria pollutants. The emission estimates shown in the table are based on vendor guarantees, Duke's experience with other similar power plants, and a BACT analysis. The annual emission rates shown in Table 4-3 include up to 1,050 hours per year of operation for each AVEF I Combined Cycle System in startup or shutdown mode. The totals in Table 4-3 do not include emissions from the diesel back-up generator and fire pump engines, which will only be used in emergencies or testing. (Estimated emissions from the two emergency engines are shown in Table 4-8.) Note that AVEF I was originally permitted at 700 hours per year of startup/shutdown, but as part of this Revision, that was increased to 1,050 hours per year. However, the annual and short term emission limits were not changed. This is due to the fact that the emissions totals are based on the number of startup/shutdown events (and associated emission rates per event as shown in the tables), not on the number of hours in startup/shutdown and the fact that the startup/shutdown duration is currently tracked by Duke on a block clock hour basis. For example, a startup event that begins 10 minutes before the hour and ends 40 minutes after the hour will be counted under the current Duke data acquisition system as 2 hours of startup, when the actual duration is 0.83 hours (50 minutes). Therefore, even though the apparent hours have increased to 1,050, the actual duration of startup/shutdown will be less.

Duke provided an estimate of 260 startup/shutdown events per year, an estimated emission rate per event, and an estimated duration per event. These estimates were developed to calculate the worst case annual emissions, and the estimates were used to develop the annual emission limits as shown in Tables 4-7b, 4-16, and 4-17. It is possible to arrive at lower annual emissions, even with a greater number of startup/shutdown events and a longer duration per event, since the emission rate for different events may be less than assumed for the emission calculations.

The hourly emission rates in Table 4-4 are the maximum emission rates under any combination of full load and ambient temperature conditions. The emission rates in Table 4-5 reflect emissions during startup and shutdown, and Table 4-7a show additional specific limits that affect emissions. Table 4-7b shows how the emissions in the preceding tables were calculated. Table 4-6 shows the auxiliary boiler emission limits, assuming that the boiler operates at 100% load for 6,000 hours per year. There is a footnote to Tables 4-1, 4-2, 4-3, 4-4, and 4-7 (shown at the end of Table 4-7) to reflect the fact that lower NO_x emission limits may be established through a 2-year demonstration period. In addition to the limits shown in the Tables, the fuel sulfur content is limited to less than 0.0075 grains per dry standard cubic foot in natural gas and 0.05 percent by weight in the diesel fuel. Cooling Tower TDS is limited to 12,000 milligrams per liter (mg/l). PM_{10} emissions were estimated for the cooling towers assuming that 31.5% of the total particulate is emitted as PM_{10}.

The emission limits for NO_x and CO are three hour rolling averages calculated from continuous monitors. The averaging times for PM_{10} and VOC are consistent with the stack emissions testing methods (3 one-hour averages). The ammonia injection rate is a 24-hour rolling average calculated from continuous ammonia injection rate monitors. SO_2 emissions are determined from fuel sulfur monitoring, normally conducted quarterly, and more frequently as required by the Permit when the Permittee can't demonstrate continuous compliance.

Table 4-3
AVEF I Rolling 12-month Total Limits

	Rolling 12-month Total Emission Limits (tons per year)				
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**
Combined Cycle System #1	19.8	121.1 Note 1	438.1	99.9	61.6
Combined Cycle System #2	19.8	121.1 Note 1	438.1	99.9	61.6
Auxiliary Boiler	0.2	3.3	14.1	0.9	1.5
Cooling Tower	NA	NA	NA	11.5 Note 2	NA
TOTAL	**39.8**	**245.5 Note 1**	**890.3**	**212.2**	**124.7**

Table 4-4
AVEF I Hourly Emission Limits During Periods When a Combined Cycle System Operates in Conditions Other than Startup or Shutdown

	Hourly Emission Limits During Periods When a Combined Cycle System Operates in Conditions Other than Startup or Shutdown (pounds per hour)				
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**
Combustion Turbine #1, Duct Burner OFF	4.00	20.2 Note 1	34.0	20.0	3.0
Combustion Turbine #1, Duct Burner ON	5.25	24.0 Note 1	62.0	24.0	12.8
Combustion Turbine #2, Duct Burner OFF	4.00	20.2 Note 1	34.0	20.0	3.0
Combustion Turbine #2, Duct Burner ON	5.25	24.0 Note 1	62.0	24.0	12.8

Table 4-5

AVEF I Emission Limits for the Combined Cycle Systems During Periods of Startup or Shutdown

	Emission Limits for the Combined Cycle Systems During Startup or Shutdown (pounds per event)		
Device	**NO_x**	**CO**	**VOC**
Combustion Turbine #1 and #2 Combined during Startup	799.0	2484.0 (Note 1)	142.0
Combustion Turbine #1 and #2 Combined during Shutdown	124.0	712.0	44.0

Note 1: There is also a maximum pounds per hour limit of 2520 lb/hr CO.

Table 4-6
AVEF I Hourly Emission Limits for the Auxiliary Boiler (Note 3)

	Hourly Emission Limits (pounds per hour)				
Device	**SO_2**	**NO_x**	**CO**	**PM_{10}**	**VOC**
Auxiliary Boiler	0.08	1.15	4.95	0.33	0.53

Table 4-7a
AVEF I Additional Concentration or Rate Emission Limits

	Concentration and Rate Limits					
Device	**NO_x**	**CO**	**PM_{10} Solids (Filterable) Alone**	**PM_{10} Total (Filterable plus Condensable)**	**VOC**	**Other**
Each Combustion Turbine #1 or #2 Exhaust when Operating in Conditions Other than Startup or Shutdown	NS	NS	9 lbs/hr	24.0 lbs/hr	NS	NS
Each Duct Burner Set #1 or #2 Exhaust	NS	NS	0.03 lb/mmBtu	NS	NS	NS
Each Combined Cycle System #1 or #2 Exhaust	3.0 ppmvd 3-hour rolling average (Note 1) and 1.6 lb/MW	20 ppmvd with Duct Burners ON and 10 ppmvd with Duct Burners OFF, 3-hour rolling average	NS	NS	4.8 ppmvd with Duct Burners ON and 1.4 ppmvd with Duct Burners OFF, 3-hour average	**Ammonia** 10 ppmvd 24-hour rolling average

Note 1: On AVEF I an SCR system will be installed that is designed to achieve a 2.5 ppmvd NO_x emission level. During the first two years of commercial operation, the NO_x emission limit is based on a 3.0 ppmvd limit, 3-hour rolling average. If, after the first two years of commercial operation, it can be shown that continual compliance can be demonstrated at levels between 2.5 and 3.0 ppm (not including startups/shutdowns and malfunctions, and considering the differences between normal operations and normal operations with supplemental duct burner firing), then the NO_x emission limit will be lowered to the demonstrated compliance levels between 2.5 and 3.0 ppm for the appropriate operational modes. To ensure

that the SCR system is properly operated to achieve the design control rate of 2.5 ppm NO_x during the first two years of commercial operation, a minimum ammonia injection rate will be used as stipulated in Condition 19.F and described in Appendix D of the Permit.
Note 2: PM_{10} emissions from the cooling tower assume 31.5% of the total particulate emitted is PM_{10}.
Note 3: Hourly Auxiliary Boiler emissions based on 105% load. Annual Auxiliary Boiler emissions are based on 6,000 hours per year at 100% load.
Note 4: ppmvd is corrected to 15% oxygen unless otherwise stated.

Table 4-7b
Federally Enforceable (BACT) Emissions from BOTH Combustion Turbine Systems At AVEF I, Including Startup and Shutdown
100% Duct Burners During All Non-Startup/Shutdown Hours,

Pollutant	Maximum Hourly Operational Emissions (lb/hr) Duct Burners ON	Annual Average Hourly Operational Emissions (lb/hr) Duct Burners ON	Maximum Startup/ Shutdown Emissions (lb/event)	Annual Operational Emissions (tpy) [Note a]	Annual Startup/ Shutdown Emissions (tpy) [Note b]	Annual Emission Rate (tons per year) Total for Both AVEF I Units
NO_x	48.0 [Note c]	45.6 [Note d]	382.0/124.0	176.4	65.8	242.2
CO	124.0 [Note e]	119.1 [Note f]	2484.0/712.0	460.7	415.5	876.2
PM_{10}	48.0	48.0	[Note g]	199.7 [Note h]	[Note g]	199.7
SO_2	10.5	9.5	[Note g]	39.5 [Note h]	[Note g]	39.5
VOC	25.6 [Note i]	25.6 [Note j]	142.0/44.0	99.0	24.2	123.2

Notes:

a. Operational hours are 8,760 – 585 hours of startup/shutdown – 438 hours (5% of 8760) of down time = 7,737 hours of operation. Annual emissions equal annual average operational hourly emission rate times 7,737 hours at 100% annual capacity and duct burners ON.
   For example, NO_x operational annual emissions are:
   (45.6 lb/hr x 7737 hrs) x 1 ton/2000 lb = 176.4 tpy
b. Startup/shutdown hours are 481 hours startup/104 hours shutdown. These hours represent 260 startup events at 1.85 hrs/event and 260 shutdown events at 0.4 hrs/event. Annual startup/shutdown emissions equal maximum startup/shutdown emissions per event times 260 events.
   For example, NO_x startup/shutdown emissions are:
   [(382.0 lb/event x 260 events/yr) + (124.0 lb/event x 260 events/yr] x 1 ton/2000 lb = 65.8 tpy
c. Based on 3.0 ppmvd, 100% load, duct burners ON.
d. Based on 3.0 ppmvd, 100% load, duct burners ON.
e. Based on 20.0 ppmvd, 100% load, duct burners ON.
f. Based on 20.0 ppmvd, 100% load, duct burners ON.
g. Startup and Shutdown emission rates are the same as operational emission rates.
h. Calculated from 8760 hours per year minus 438 hours (5% of 8760) = 8,322 hrs times the hourly emission rate.
i. Based on 4.8 ppmvd, 100% load, duct burners ON.
j. Based on 4.8 ppmvd, 100% load, duct burners ON.

Table 4-8

AVEF I Emission Estimates for the Emergency Engines
(Emissions based on 500 hours of operation per year)

Device	Emission Estimates (tons per year)				
	SO_2	NO_x	CO	PM_{10}	VOC
Diesel Fire Water Pump Engine (200 hp)	0.1	1.6	0.3	0.1	0.1
Diesel Back-up Generator Engine (750 hp)	0.1	3.6	3.5	0.2	0.4

C. Emissions from AVEF II

Tables 4-9 through 4-17 display the proposed maximum permit limits (potential to emit, or PTE) with pollution controls from the AVEF II systems for the criteria pollutants. The emission estimates shown in the table are based on vendor guarantees, Duke's experience with other similar power plants, and a LAER/BACT analysis. Under an agreement with the Arizona Corporation Commission (ACC), Duke has agreed voluntarily to install controls that are equivalent to the lowest achievable emissions rate on the CTGs. However, this is a locally enforceable condition only. Furthermore, Duke's agreement is not needed to avoid any otherwise applicable requirement. Federal and County regulations only require BACT at this facility. Therefore, the permit contains two sets of emission limits, one for BACT and one for the voluntarily accepted, locally enforceable limits (LEL). These dual limits are shown in the following tables.

The annual emission rates shown in Tables 4-9 and 4-10 include startup and shutdown using the same methodology previously described for AVEF I. The totals in Tables 4-9 and 4-10 do not include emissions from the diesel back-up generator and fire pump engines, which will only be used in emergencies or testing. (Estimated emissions from the two emergency engines are shown in Table 4-15.) The hourly emission rates in Table 4-11 are the maximum emission rates under any combination of full load and ambient temperature conditions. The emission rates in Table 4-12 reflect emissions during startup and shutdown, and Table 4-14 shows additional specific limits that affect emissions. Table 4-13 shows the auxiliary boiler emission limits. In addition to the limits shown in the Tables, the fuel sulfur content is limited to less than 0.0075 grains per dry standard cubic foot in natural gas and 0.05 percent by weight in the diesel fuel. Cooling Tower TDS is limited to 12,000 milligrams per liter (mg/l).

The emission limits for NO_x and CO are calculated from continuous monitors. The averaging times for PM_{10} and VOC are consistent with the stack emissions testing methods. The ammonia injection rate is calculated from continuous ammonia injection rate monitors. SO_2 emissions are determined from fuel sulfur monitoring, normally conducted quarterly, and more frequently as required by the Permit when the Pemittee can't demonstrate continuous compliance.

Table 4-9
AVEF II Rolling 12-month Total Federally Enforceable Limits at BACT

Device	Rolling 12-month Total Emission Limits (tons per year)				
	SO_2	NO_x	CO	PM_{10}	VOC
Combined Cycle System #3	26.7	101.2 Note 5	270.2	104.0	59.7
Combined Cycle System #4	26.7	101.2 Note 5	270.2	104.0	59.7
Auxiliary Boiler	0.2	3.3	14.1	0.9	1.5
Cooling Tower	NA	NA	NA	7.5 Note 6	NA
TOTAL	**53.6**	**205.7**	**554.5**	**216.4**	**120.9**

Table 4-10
AVEF II Rolling 12-month Total Locally Enforceable Limits

Device	Rolling 12-month Total Emission Limits (tons per year)				
	SO_2	NO_x	CO	PM_{10}	VOC
Combined Cycle System #3	26.7	101.2	249.4	79.1	35.9
Combined Cycle System #4	26.7	101.2	249.4	79.1	35.9
Auxiliary Boiler	0.2	3.3	14.1	0.9	1.5
Cooling Tower	NA	NA	NA	7.5 Note 6	NA
TOTAL	**53.6**	**205.7**	**512.9**	**166.6**	**73.3**

Table 4-11
AVEF II Hourly Emission Limits During Periods When a Combined Cycle System Operates in Conditions Other than Startup or Shutdown

	Hourly Emission Limits During Periods When a Combined Cycle System Operates in Conditions Other than Startup or Shutdown (pounds per hour)				
Device	SO_2	NO_x	CO	PM_{10}	VOC
Combustion Turbine #3, Duct Burner OFF	LEL 5.0 BACT 5.0	LEL 13.4 BACT 13.4 Note 5	LEL 8.2 BACT 8.2	LEL 15.0 BACT 18.0	LEL 2.3 BACT 2.3
Combustion Turbine #3, Duct Burner ON	LEL 6.5 BACT 6.5	LEL 18.4 BACT 18.4 Note 5	LEL 11.2 BACT 16.8	LEL 19.0 BACT 25.0	LEL 6.4 BACT 12.8
Combustion Turbine #4, Duct Burner OFF	LEL 5.0 BACT 5.0	LEL 13.4 BACT 13.4 Note 5	LEL 8.2 BACT 8.2	LEL 15.0 BACT 18.0	LEL 2.3 BACT 2.3
Combustion Turbine #4, Duct Burner ON	LEL 6.5 BACT 6.5	LEL 18.4 BACT 18.4 Note 5	LEL 11.2 BACT 16.8	LEL 19.0 BACT 25.0	LEL 6.4 BACT 12.8
LEL = Locally Enforceable Level, BACT = Federally Enforceable Best Available Control Technology Limits					

Table 4-12
AVEF II Emission Limits for the Combined Cycle Systems During Periods of Startup or Shutdown

	Emission Limits for the Combined Cycle Systems During Startup or Shutdown (pounds per event)		
Device	NO_x	CO	VOC

Combustion Turbine #3 and #4 Combined	799.0	2484.0 [Note 1]	142.0
Combustion Turbine #3 and #4 Combined during Shutdown	124.0	712.0	44.0

Note 1: There is also a maximum pounds per hour limit of 2520 lb/hr CO.

Table 4-13
AVEF II Hourly Emission Limits for the Auxiliary Boiler
(Note 7)

Device	**Hourly Emission Limits (pounds per hour)**				
	SO_2	**NO_x**	**CO**	**PM_{10}**	**VOC**
Auxiliary Boiler	0.08	1.15	4.95	0.33	0.53

Table 4-14
AVEF II Additional Concentration or Rate Emission Limits

Device	Concentration and Rate Limits					
	NO_x	**CO**	**PM_{10} Solids (Filterable) Alone**	**PM_{10} Total (Filterable plus Condensable)**	**VOC**	**Other**
Each Combustion Turbine #3 or #4 Exhaust when Operating in Conditions Other than Startup or Shutdown	NS	NS	9 lbs/hr	**LEL** 15.0 lb/hr Duct Burners OFF, 19.0 lb/hr Duct Burners ON **BACT** 18.0 lbs/hr Duct Burners OFF, 25.0 lb/hr Duct Burners ON	NS	NS
Each Duct Burner Set #1 or #2 Exhaust	NS	NS	0.03 lb/mmBtu	NS	NS	NS
Each Combined Cycle System #1 or #2 Exhaust	**LEL** 2.0 ppmvd, 1-hour average. **BACT** 2.0 ppmvd 3-hour rolling average Note 5 **NSPS** 1.6 lb/MW	**LEL** 2.0 ppmvd, 3-hour rolling average. **BACT** 3.0 ppmvd with Duct Burners ON and 2.0 ppmvd with Duct Burners OFF, 3-hour rolling average	NS	NS	**LEL** 2.0 ppmvd with Duct Burners ON and 1.0 ppmvd with Duct Burners OFF, 3-hour average **BACT** 4.0 ppmvd with Duct Burners ON and 1.0 ppmvd with Duct Burners	**Ammonia** 10 ppmvd 24-hour rolling average

					OFF, 3-hour average	

Note 5: On AVEF II an SCR system will be installed that is designed to achieve a 1-hr average 2.0 ppmvd NO_x emission level. During the first two years of commercial operation, the NO_x emission limit is based on a 2.0 ppmvd limit, 3-hour rolling average. After the first two years of commercial operation, emissions shall not exceed 2.0 ppmvd, 1-hr average, unless the Permittee can demonstrate that the facility has not been able to meet that limit.
Note 6: PM_{10} emissions from the cooling tower assume 31.5% of the total particulate emitted is PM_{10}.
Note 7: Hourly Auxiliary Boiler emissions based on 105% load. Annual Auxiliary Boiler emissions are based on 6,000 hours per year at 100% load.

Table 4-15
AVEF II Emission Estimates for the Emergency Engines

Device	Emission Estimates (tons per year)				
	SO_2	NO_x	CO	PM_{10}	VOC
Diesel Fire Water Pump Engine (200 hp)	0.1	1.6	0.3	0.1	0.1
Diesel Back-up Generator Engine (740 hp)	0.1	3.6	3.5	0.2	0.4

Tables 4-16 and 4-17 show how the emission limits shown in Tables 4-9 and 4-10 were calculated.

Table 4-16
Federally Enforceable (BACT) Emissions from BOTH Combustion Turbine Systems At AVEF II, Including Startup and Shutdown
100% Duct Burners During All Non-Startup/Shutdown Hours,

Pollutant	Maximum Hourly Operational Emissions (lb/hr) Duct Burners ON	Annual Average Hourly Operational Emissions (lb/hr) Duct Burners ON	Maximum Startup/ Shutdown Emissions (lb/event)	Annual Operational Emissions (tpy) [Note a]	Annual Startup/ Shutdown Emissions (tpy) [Note b]	Annual Emission Rate (tons per year) Total for Both AVEF II Units
NO_x	36.7 [Note c]	35.3 [Note d]	382.0/124.0	136.6	65.8	202.4
CO	33.5 [Note e]	32.3 [Note f]	2484.0/712.0	125.0	415.5	540.4
PM_{10}	50.0	50.0	[Note g]	208.1 [Note h]	[Note g]	208.1
SO_2	12.9	12.8	[Note g]	53.5 [Note h]	[Note g]	53.3
VOC	25.6 [Note i]	24.6 [Note j]	142.0/44.0	95.2	24.2	119.4

Notes:

a. Operational hours are 8,760 – 585 hours of startup/shutdown – 438 hours (5% of 8760) of down time = 7,737 hours of operation. Annual emissions equal annual average operational hourly emission rate times 7,737 hours at 100% annual capacity and duct burners ON.
   For example, NO_x operational annual emissions are:
   (36.7 lb/hr x 7737 hrs) x 1 ton/2000 lb = 136.6 tpy

b. Startup/shutdown hours are 481 hours startup/104 hours shutdown. These hours represent 260 startup events at 1.85 hrs/event and 260 shutdown events at 0.4 hrs/event. Annual startup/shutdown emissions equal maximum startup/shutdown emissions per event times 260 events.

For example, NO_x startup/shutdown emissions are:

[(382.0 lb/event x 260 events/yr) + (124.0 lb/event x 260 events/yr)] x 1 ton/2000 lb = 65.8 tpy

c. Based on 2.0 ppmvd, 100% load, duct burners ON.
d. Based on 2.0 ppmvd, 100% load, duct burners ON.
e. Based on 3.0 ppmvd, 100% load, duct burners ON.
f. Based on 3.0 ppmvd, 100% load, duct burners ON.
g. Startup and Shutdown emission rates are the same as operational emission rates.
h. Calculated from 8760 hours per year minus 438 hours (5% of 8760) = 8,322 hrs times the hourly emission rate.
i. Based on 4.0 ppmvd, 100% load, duct burners ON.
j. Based on 4.0 ppmvd, 100% load, duct burners ON.

Table 4-17
Locally Enforceable Emissions from BOTH Combustion Turbine Systems At AVEF II, Including Startup and Shutdown 100% Duct Burners During All Non-Startup/Shutdown Hours,

Pollutant	Maximum Hourly Operational Emissions (lb/hr) Duct Burners ON	Annual Average Hourly Operational Emissions (lb/hr) Duct Burners ON	Maximum Startup/ Shutdown Emissions (lb/event)	Annual Operational Emissions (tpy) [Note k]	Annual Startup/ Shutdown Emissions (tpy) [Note l]	Annual Emission Rate (tons per year) Total for Both AVEF II Units
NO_x	36.7 [Note m]	35.3 [Note n]	382.0/124.0	136.6	65.8	202.4
CO	22.3 [Note o]	21.5 [Note p]	2484.0/712.0	83.2	415.5	498.7
PM_{10}	38.0	38.0	[Note q]	158.1 [Note r]	[Note q]	158.1
SO_2	12.9	12.8	[Note q]	53.3 [Note r]	[Note q]	53.3
VOC	12.8 [Note s]	12.3 [Note t]	142.0/44.0	47.6	24.2	71.8

Notes:

k. Operational hours are 8,760 – 585 hours of startup/shutdown – 438 hours (5% of 8760) of down time = 7,737 hours of operation. Annual emissions equal annual average operational hourly emission rate times 7,737 hours at 100% annual capacity and duct burners ON.

For example, NO_x operational annual emissions are:

(35.3 lb/hr x 7737 hrs) x 1 ton/2000 lb = 136.6 tpy

l. Startup/shutdown hours are 481 hours startup/104 hours shutdown. These hours represent 260 startup events at 1.85 hrs/event and 260 shutdown events at 0.4 hrs/event. Annual startup/shutdown emissions equal maximum startup/shutdown emissions per event times 260 events.

For example, NO_x startup/shutdown emissions are:

[(382.0 lb/event x 260 events/yr) + (124.0 lb/event x 260 events/yr)] x 1 ton/2000 lb = 65.8 tpy

m. Based on 2.0 ppmvd, 100% load, duct burners ON.
n. Based on 2.0 ppmvd, 100% load, duct burners ON.
o. Based on 2.0 ppmvd, 100% load, duct burners ON.

p. Based on 2.0 ppmvd, 100% load, duct burners ON.
q. Startup and Shutdown emission rates are the same as operational emission rates.
r. Calculated from 8760 hours per year minus 438 hours (5% of 8760) = 8,322 hrs times the hourly emission rate.
s. Based on 2.0 ppmvd, 100% load, duct burners ON.
t. Based on 2.0 ppmvd, 100% load, duct burners ON.

For both AVEF I and II, commencement of startup and shutdown is referenced to being in a combustion turbine operating mode other than Mode 6. The turbine control system records the operating mode, and the permit requires such recording. Startup is defined as the period starting between when fuel is first combusted in the combustion turbine, and ending upon initiation of dry, low-NOx operation as indicated by receipt of a Mode 6 signal from the turbine control system. Shutdown is defined as the period of time following normal operations starting when the Mode 6 signal from the turbine control system is lost, and ending when fuel is no longer being combusted in the combustion turbine. Mode 6 is defined as the cycle of machine operation where fuel combustion is occurring in all six burners which comprise the GE Dry Low NO_x (DLN) combustion system. During Mode 6 combustion, excess air dilutes the flame zone in a manner that minimizes combustion temperatures resulting in lower thermal NOx formation while allowing for CO "burnout" in the combustor. CO "burnout" results in oxidation of CO to CO_2. An unambiguous output signal is available from the turbine control system indicating when the turbine is in Mode 6 operation.

It is important to distinguish the "startup" emissions discussed in the following paragraphs and the above tables, from emissions that occur during the construction portion of the project, sometimes referred to as "commissioning." During commissioning, the turbine, duct burners, and associated equipment must go through a testing and tuning stage before any normal mode of operation can be achieved and before the emission limits in the permit apply. The USEPA has recognized that emissions during commissioning are construction emissions. For example, in a letter dated December 4, 2001 from Mr. Gerardo Rios (USEPA Region IX) to Mr. Steve Peplau (MCESD), USEPA confirmed that the "EPA considers boilout of gas turbines and associated HRSGs to be construction activities and, as such, should not be considered initial startup of operations." The New Source Performance Standards (NSPS) effectively limit the commissioning period to no longer than 180 days since the NSPS limits apply no later than 180 days after "initial start" of the units. Initial start is defined in 40 CFR 60.2 as "setting in operation … for any purpose." Therefore, the commissioning period cannot last for more than 180 days and will likely last for a much shorter time period (since the applicant has a significant economic incentive to get the units on line as quickly as possible).

V. APPLICABILITY OF NEW SOURCE REVIEW

Since AVEF I and AVEF II are located outside of the designated County non-attainment area, they are reviewed only as a PSD source, not a non-attainment source. However, County Rule 240 also requires an analysis of the impacts of the source on the ozone nonattainment area. (This is discussed in Section IX, following).

Since AVEF I and AVEF II are both steam electric generating units, they are one of the 28 major source categories for which the PSD threshold is 100 tons per year PTE. This threshold is exceeded at both AVEF I and AVEF II for NO_x, CO, VOC and PM_{10}. It is not exceeded for SO_2.

PSD New Source Review requires an analysis of Best Available Control Technology (BACT) for those pollutants that exceed the applicable PSD trigger levels; an ambient air quality impacts analysis for increment consumption and National Ambient Air Quality Standards (NAAQS) for all criteria pollutants (whether or not they exceed thresholds); a visibility and other air quality related values (AQRVs) impact analysis for all criteria pollutants that could affect Class I Areas; and an "additional impacts analysis", including visibility, for non-Class I areas. MCESD rules also require an analysis of the impact of AVEF I and AVEF II on ozone concentrations in the nonattainment area. In addition to the PSD review for criteria pollutants, MCESD policy requests an air toxics ambient impact evaluation for those chemicals listed by the Arizona Department of Environmental Quality (ADEQ) under its draft Arizona Ambient Air Quality Guidelines (AAAQGs) policy. Each of these elements will be discussed in the following sections.

VI. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

A "top down" analytical procedure is required to establish a BACT emission limit that represents the most stringent control technique available, taking cost and other environmental factors into account. The procedure includes the following elements:

- Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation
- Eliminate the technically infeasible or unavailable technology options
- Rank the remaining control technologies by control effectiveness (cost and emissions reductions)
- Evaluate the most effective controls and select the most stringent technique based on energy, environmental and economic impacts.

Duke provided a detailed BACT analysis for each of the emitting units. That analysis was reviewed by MCESD and the results are summarized in the following subsections. Duke provided a thorough analysis of BACT for all emitting systems, including the diesel-fueled engines (fire water pumps and back-up generators engines). The engines will be operated only for testing or for emergency situations. Therefore, good combustion control of modern engines was determined as BACT for the fire water pumps and the back-up generators engines. (Note that the back-up generators are not used to provide electrical power to the grid, but are for a "black start" condition when no other power source is available to the facility).

Due to the fact that AVEF I was permitted approximately one year prior to submittal of the AVEF II Significant Permit Revision request, the two facilities have different BACT determinations. This is because BACT is a case by case analysis that can become more stringent over time. The AVEF I BACT analysis will be discussed first, followed by the AVEF II analysis.

A. NO_x from the AVEF I Combined Cycle Systems

In the AVEF I Combined Cycle Systems, NO_x is emitted from the combustion turbine and duct burners. Duke proposed an SCR system coupled with a low-NO_x combustor and an emission limit after controls of 3 parts per million by volume corrected to 15% oxygen (3 ppmvd) on a rolling 3-hour average.

Emission reduction systems evaluated from most to least stringent were: SCONOX, SCR plus low-NO_x combustor, XONON, and SCR plus water/steam injection or advanced low-NO_x combustor. Only the SCONOX system could theoretically achieve emission levels lower than 3 ppm for the proposed combined cycle systems proposed by Duke for AVEF I. (The AVEF I duct burners are relatively large, about 360 mmBtu/hr, which is not typical for previously permitted combined cycle systems.) The SCONOX system has not yet been installed on larger (i.e., over about 25 MWe) systems, but beta tests of SCONOX on larger systems similar to AVEF I have been recently permitted.

When Duke filed its original permit application for AVEF I (October 1999), the SCONOX vendor (Goal Line Technologies) would not guarantee performance for the larger systems. However, in December, 1999, Goal Line Technologies announced that it would guarantee performance on large systems, although there still have not been any such systems installed and there remain significant concerns regarding operational reliability and validity of the guarantee on large systems. Since SCONOX has not been installed or demonstrated on larger systems, it is not considered a technically feasible option.

Nevertheless, Duke calculated the cost of SCONOX per ton of NO_x removed as if SCONOX could be installed and meet an emission limit of 2 ppm on a 3-hour rolling average basis.
The cost per ton removed under this scenario was $23,800. This can be compared to the cost per ton removed with the proposed SCR plus low-NO_x combustor at 3 ppm of $4,700 per ton removed, only one-fifth the cost. Although SCONOX has an additional benefit of removing CO as well as NO_x, and SCR has the potential disbenefit of low levels of ammonia emissions ("ammonia slip"), the lack of technical feasibility and the high cost per ton removed eliminated SCONOX as a viable BACT.

The next most stringent technology for AVEF I is the proposed SCR plus low-NO_x combustor at 3 ppm. However, at the time AVEF I was being permitted, there were reported cases of SCR systems being permitted as low as 2.5 ppm on larger systems similar (but with much smaller duct burners) to AVEF I. Therefore, an analysis of the incremental costs associated with going to 2.5 ppm was conducted, and it was found that the incremental cost of moving from 3 ppm to 2.5 ppm was $31,600 per ton removed (more than 6 times the cost of a 3 ppm limit). In addition, because of system variability and continuous emission monitor variance at lower NO_x emission levels, AVEF I will have to be designed to meet a 2.5 ppm routinely. Therefore, it was concluded that a 3 ppm, 3-hour rolling average limit was BACT.

However, in response to public comment, AVEF I volunteered to install an SCR system that is designed to achieve 2.5 ppmvd NO_x control levels. Based on concerns over the capability of NO_x CEM monitors to accurately determine compliance and the capability of the SCR system to reliably achieve these low concentration levels on a routine basis, the Permit does not initially include a 2.5 ppmvd NO_x BACT emission limit. Instead, during the first two years of commercial operation, the BACT emission limit is based on 3.0 ppmvd, 3-hour rolling average. If, after the first two years of commercial operation, it can be shown that continual compliance can be demonstrated by the NO_x CEM monitor at levels between 2.5 and 3.0 ppm (not including startups/shutdowns and malfunctions, and considering the differences between normal operations and normal operations with supplemental duct burner firing), then the BACT emission limits will be lowered to the demonstrated compliance levels between 2.5 and 3.0 ppmvd for normal operations and/or normal operations with supplemental duct burner firing.

To ensure that the SCR system at AVEF I is properly operated to achieve the design control rate of 2.5 ppmvd NO_x, the permit also contains a "minimum ammonia injection rate" requirement for the first two years of commercial operation. The minimum injection rate will be determined by continuously monitoring the NO_x concentration at the SCR inlet and calculating the minimum stoichiometric ammonia injection rate needed to achieve 2.5 ppmvd SCR performance. The actual ammonia injection rate will be monitored and compared to the calculated minimum rate. The calculation methodology is included as Appendix D in the Permit.

B. NO_x from the AVEF I Auxiliary Boiler

The initial AVEF I permit was for an Auxiliary Boiler limited to no more than 1,000 hours per year of operation. Duke proposed a BACT NO_x limit of 3.1 pounds per hour (lb/hr) equivalent to 0.11 lb/mmBtu. (The boiler was rated at 29.3 mmBtu per hour, HHV). This was to be accomplished through low-NO_x burners. No other emission reduction technology is cost-effective for this small of a unit with such small emissions (less than 1.6 tons per year).

In the minor revision, Duke changed the boiler to a 33 mmBtu/hr boiler (higher heating value at 105% load). In the significant revision, Duke changed the hours of operation from 1,000 to as much as 6,000 hours per year. The annual emission limit assumes 100% load for 6,000 hours, but Duke anticipates an average annual load of about 20%. The hourly emission limit assumes 105%

load. The proposed BACT is a NO_x emission rate of 0.035 lb/mmBtu. (See the expanded discussion of BACT for the Auxiliary Boiler in the AVEF II section of this document).

C. CO from the AVEF I Combined Cycle Systems

In the AVEF I Combined Cycle Systems, CO is emitted from the combustion turbine and duct burners. Duke proposed good combustion practice with an emission limit of 20 ppm corrected to 15% oxygen on a rolling 24-hour average with duct burners on and 10 ppm without duct burners. Through the BACT review, the limit was made more stringent to 10/20 ppm on a 3-hour rolling average basis.

Emission reduction systems evaluated from most to least stringent were an oxidation catalyst and good combustion control. Two oxidation catalyst systems were evaluated, (1) the SCONOX combined CO and NO_x removal system and (2) a stand-alone oxidation catalyst.

The SCONOX system has already been eliminated as not technically feasible and very costly. Therefore, it was not further evaluated for CO control. A stand-alone oxidation catalyst was evaluated in detail since it is technically feasible and MCESD is considering such requirements for some other facilities located in the Phoenix metropolitan area (i.e., within the CO nonattainment boundary that requires a Lowest Achievable Emission Rate, LAER, decision).

Duke calculated the cost per ton removed with an oxidation catalyst under several different scenarios and found the costs to be from $3,900 to $7,400 per ton removed. This cost is essentially infinitely greater than the cost for good combustion control (since one would practice good combustion control even when using an oxidation catalyst). In addition, oxidation catalysts generate additional PM_{10} emissions. The relatively high cost and other disbenefits of the oxidation catalyst led to selecting good combustion control as BACT for CO from the Combined Cycle Systems.

The emission limit of 10/20 ppm, 3-hour rolling average, duct burners OFF/ON was selected based on the RACT/BACT/LAER Clearinghouse (RBLC) data and vendor guarantees.

D. CO from the AVEF I Auxiliary Boiler

The original AVEF I permit required good combustion control at 3.95 pounds per hour (0.13 lb/mmBtu) as BACT for the Auxiliary Boiler. Considering the small emissions (2.1 tons per year) an oxidation catalyst is clearly not cost-effective.

As part of the change in boiler rating (discussed under the NO_x section) and the increased hours, the NO_x level was significantly reduced (less than 50%) and a special Low NO_x Burner with Flue Gas Recirculation (LNB-FGR) was required. Since there is a trade off between NO_x and CO, the CO level had to be increased slightly to 0.150 lb/mmBtu in order to achieve the NO_x reduction. (See the expanded discussion of BACT for the Auxiliary Boiler in the AVEF II section of this document).

E. PM_{10} from the AVEF I Combined Cycle Systems

Filterable PM_{10} emissions from natural gas-fired AVEF I Combined Cycle Systems are relatively small. In addition, no post-combustion control systems have been installed to control PM_{10} from gas-fired units. Therefore, good combustion control is considered BACT for PM_{10} from the Combined Cycle systems.

A dual emission limit was established for PM_{10} from each AVEF I Combined Cycle system of 9 pounds per hour for the filterable (Method 5) particulate and 20 pounds per hour for filterable plus condensable particulate combined (Method 5 plus Method 202 combined) from the combustion turbines alone. There will be an additional 4 pounds per hour for filterable plus condensable particulate combined for each duct burner (i.e., 31 pounds per hour total particulate per Combined Cycle System when the duct burners are on).

The dual emission limit was established to ensure that good combustion control commensurate with other similar permitted systems was maintained, while still allowing for the uncertainty recently discovered regarding condensable particulate emission limits from gas-fired combustion turbines. The Method 5 particulate limit without duct burners is equivalent to approximately 0.004 lb/mmBtu, consistent with the most stringent emission limits in the RBLC.

F. PM_{10} from the AVEF I Auxiliary Boiler

The emission rate is BACT and it is achieved through good combustion practice.

G. PM_{10} from the AVEF I Cooling Tower

There is a potential for PM_{10} emissions from condensation of water droplets that drift away from the AVEF I cooling tower. There are two primary factors that control the amount of PM_{10} from the cooling tower: maximum total dissolved solids (TDS) in the cooling tower water and droplet drift rate.

A droplet drift rate of 0.001 percent resulting from installation of high efficiency drift eliminators on the AVEF I cooling tower was concluded as BACT. This limit can be compared to USEPA assumed drift rates (in AP-42) of 0.02 percent and Duke's original proposal of 0.003 percent. The permitted drift rate is based on vendor guarantees and is consistent with the most stringent limits listed in the RBLC.

The second parameter affecting PM_{10} from the cooling towers is TDS loading limits. The TDS is limited to 12,000 ppm (weight). This limit is a balance between the need to keep the TDS low and the need to minimize water usage (which forces the TDS higher). TDS is required to be monitored on an essentially continuous basis (through conductivity measurements) with monthly TDS laboratory analysis.

As part of the AVEF II Significant Revision application, Duke provided information indicating that the PM_{10} fraction of the total particulate emitted should be less than 15%. However, this fraction is highly dependent upon the assumed droplet size distribution. The USEPA has generally assumed that 50% of the total particulate is PM_{10}, and this value was initially used in the AVEF I permit. However, this fraction is an assumption not based on data. MCESD has previously permitted at least one power plant assuming 31.5% of the total particulate is PM_{10}. The 31.5% value was based on some cooling tower emission tests, and is consistent with the data presented by Duke. Therefore, for this significant permit revision, the PM_{10} fraction is assumed to be 31.5% for both AVEF I and AVEF II.

H. VOC from the AVEF I Combined Cycle Systems

The permitted limit is 3 lb/hr for each of the Combustion Turbines (equivalent to 1.4 ppm or 0.0017 lb/mmBtu) and an additional 9.8 lb/hr for each duct burner (equivalent to 0.027 lb/mmBtu). The emission rate is BACT and it is achieved through good combustion practice.

Duke evaluated SCONOX, oxidation catalysts, and combustion control for VOC emission reduction. SCONOX was eliminated previously, and the cost per ton of VOC removed by an oxidation catalyst was $68,200; which is not cost-effective. The VOC limits proposed are consistent with the most stringent in the RBLC.

I. VOC from the AVEF I Auxiliary Boiler

Duke proposed good combustion control and a limit of 0.42 lb/hr (equivalent to 0.014 lb/mmBtu) for the AVEF I Auxiliary Boiler.

Post combustion controls on the auxiliary boiler are not cost feasible and the emission limit is consistent with the RBLC.

J. BACT for the AVEF II Combustion Turbine Systems

The AVEF II combustion turbine systems include the combustion turbine generator (CTG) and a supplementary fired (i.e., duct burner) heat recovery steam generator (HRSG). The CTG and HRSG exhaust through a single stack for each unit. (Therefore, there are two exhaust stacks associated with AVEF II and two with AVEF I, one for each combustion turbine system, termed a "unit" herein.)

At AVEF II, prior to exiting the exhaust stack, the flue gas is treated with a selective catalytic reduction (SCR) system to remove nitrogen oxides (NO_x) and a catalytic oxidizer (CAT-OX) to remove carbon monoxide (CO). Duke proposed the SCR and CAT-OX as the equipment chosen to reach BACT levels for NO_x and CO, respectively. In addition, the CAT-OX is effective at reducing volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). Duke proposed emission limits of 2.5 parts per million by volume dry (ppmvd) NO_x based on a 3-hour rolling average, 4 ppmvd for CO based on a 3-hour rolling average (NO_x and CO corrected to 15% oxygen), 1 ppmvd VOC based on a 3-hour rolling average with duct burners off, and 4 ppmvd VOC based on a 3-hour rolling average with duct burners on. These emission limits are a combined limit for each unit including pollutants generated from both the CTGs and the duct burners for that unit.

Duke is proposing to use only commercial pipeline quality natural gas with a sulfur content of less than 0.75 grains sulfur per 100 standard cubic feet (0.0075 gr/scf) as the fuel source for the combustion turbine systems. The use of such a fuel is considered by Duke to be BACT for sulfur dioxide (SO_2) emissions.

AVEF II has relatively large duct burners, each rated at 670 mmBtu/hr (higher heating value). Duke reports that when the duct burners are operated at full capacity, the duct burners consume approximately 25% to 30% of the fuel being consumed by the combustion turbine system (i.e., CTG plus duct burner).

In order to determine the BACT level for the combustion turbine systems, seven data sources were considered:

- Combustion turbine system vendor information
- Engineering cost analysis
- Previous Pima County, Pinal County, Arizona State permitting decisions
- Previous Maricopa County permitting decisions
- California Air Pollution Control Officers (CAPCOA) BACT Clearinghouse
- RACT/BACT/LAER Clearinghouse (RBLC)
- Previous USEPA and other agency permitting decisions

These data sources were recommended by the USEPA and have been used in previous Maricopa County permitting decisions.

J.1 Vendor Information for SO_2 and PM_{10}

There are no technically or economically feasible post combustion emission control systems for SO_2 and PM_{10} from modern natural gas fueled combustion turbine systems and no post-combustion emission control systems have been required at other locations. Therefore, BACT for

SO_2 and PM_{10} is the emission rate produced by commercial pipeline quality natural gas fired with good combustion practices.

Commercial pipeline quality natural gas has a sulfur content of less than 0.75 grains per 100 dry standard cubic feet (0.0075 gr/scf). At this level of sulfur content, the SO_2 emissions are 6.3 pounds per hour per unit (including duct firing) or 24.8 tons per year per unit (49.6 tpy both units combined).

PM_{10} emissions current practice is to include both the front half (filterable) and back half (condensable) particulate in the PM_{10} total emission limit. The front half (Method 5) limit for AVEF II was set at 9 pounds per hour per unit, consistent with the AVEF I BACT of 0.005 lb/mmBtu with duct burners off. The combined front half (Method 5) and back half (Method 202) limit was set at a total of 18 lb/hr per unit with duct burners off as proposed by Duke. This limit is less than the BACT for AVEF I, which is 20 lb/hour (with duct burners off). The duct burners add 4 lb/hr for AVEF I and 7 lb/hr for AVEF II. The AVEF II duct burners are larger than AVEF I.

J.2 Vendor Information for NO_x and CO

Duke has worked with a number of SCR and CAT-OX vendors and has permitted a number of plants throughout the United States. The proposed limits, 2.5 ppmvd 3-hour NO_x and 4 ppmvd 3-hour CO are considered by Duke to be the lowest emission rates which have been demonstrated in practice. These emission limits will be met through SCR for NO_x control and CAT-OX for CO (and VOC) control.

J.3 Engineering Cost Analysis for NO_x Removal

Although SCR is the current state of the art control system for reducing NO_x emissions from large natural gas fired combustion turbine systems, Duke examined the cost and technical feasibility of four technologies: SCONOX, SCR with low NO_x combustor (as proposed for AVEF II), XONON, and SCR with water/steam injection or an advanced low NO_x combustor.

Despite the fact that the SCONOX system has not been demonstrated on large combustion turbine systems, the manufacturer claims that they can provide a guaranteed emission limit for large systems. Therefore, the cost effectiveness of SCONOX was evaluated. The XONON system, however, has not been demonstrated on large systems and the manufacturer will not issue a guarantee for such large systems. Therefore, the XONON system was eliminated from consideration due to technical feasibility.

There are a number of technical difficulties that must be overcome in order for SCONOX to be viable for large systems, and a demonstration project is being undertaken at a plant located at Otay Mesa near San Diego, California. In addition to the technical issues, however, Duke estimated the cost effectiveness of the SCONOX system at approximately $14,500 per ton removed (based on total tons removed). Therefore, SCONOX is not considered a cost-effective technology. In addition, the modern SCR systems can achieve essentially the same NO_x emission limits as the SCONOX technology.

SCR with low NO_x burners can achieve emission limits on the order of 2 to 3 ppmvd, while SCR with water/steam injection achieves emission limits on the order of 6 ppmvd. Therefore, if SCR with low NO_x burners is technically and economically feasible, it is preferred over the water/steam injection systems. Indeed, this is the case for AVEF II, and SCR with low NO_x burners was selected as BACT.

J.4 Previous Agency Permitting Decisions for NO_x

Once SCR with low NO_x burners was selected as technologically feasible, the question becomes what emission limit is required. A review of Pima County, Pinal County, Arizona State, and

Maricopa County permitting decisions indicate that the lowest emission limit permitted prior to mid-2001 was 2.5 ppmvd, 3-hour average. However, review of other agency permitting decisions (e.g., California, Connecticut, Massachusetts, Nevada, Washington) indicates that some units have recently been permitted as low as 2.0 ppmvd, 1-hour average. The USEPA Region IX believes that 2.0 ppmvd, 1-hour is the point of departure for LAER decisions. However, none of the units permitted at 2.0 ppmvd have been built and placed into commercial operation. In addition, SCR vendors have been reluctant to guarantee such low levels except under the most narrow of circumstances, circumstances that are not routinely met in operation of a merchant plant.

Since the data in the USEPA RACT/BACT/LAER and the CAPCOA LAER/BACT Clearinghouses tend to be dated, the permit limits in the Clearinghouses were greater than the limits established in the recently issued permits. Therefore, the recently issued permits were considered precedent.

The size of the duct burners and the duct burner NO_x contribution are major variables in comparing permitting decisions for various units. None of the plants permitted at 2.0 ppmvd, 1-hour have duct burners as large as those proposed by Duke (each AVEF II duct burner is rated at 670 mmBtu/hr HHV). NO_x formation in duct burners is more difficult to control than in the combustion turbine. The AVEF II duct burners are responsible for 25% to 30% of the fuel combusted in the combined cycle system and a significant fraction of the total NO_x being emitted. (Duke indicates that the duct burner contribution is approximately 1 ppmvd in the uncontrolled combustion system exhaust).

Duke provided an engineering economic analysis of the difference in cost between 2.0 ppmvd and 2.5 ppmvd NO_x emission limits. The difference in cost for the SCR system for a 2.0 ppmvd versus a 2.5 ppmvd limit is relatively low, on the order of $150,000 annualized capital plus O&M costs per year per unit, but the difference in amount removed for 2.0 ppmvd versus 2.5 ppmvd is also relatively small, on the order of 14 tpy per unit. This is an incremental cost per ton removed of about $10,000 per incremental ton. However, Duke contends that the real cost is the cost of potential non-compliance (where the SCR system simply cannot reach 2.0 ppmvd) and an entire new system (e.g., a SCONOX system) would have to be installed in place of the SCR. When this possibility is included in the engineering cost analysis (assuming a 5% probability of that occurring at the 2.5 ppmvd level, and a 15% probability at the 2.0 ppmvd level), the cost effectiveness goes from $7,900 per total ton removed for 2.5 ppmvd to $10,800 per total ton removed (and $48,600 per incremental ton removed). Obviously, with a contingency, the incremental cost per ton removed becomes quite high.

J.5 Permit Limits for NO_x from AVEF II

The economic and technical feasibility analysis indicate that the level Duke proposed, 2.5 ppmvd 3-hour average with duct burners is BACT. However, considering the apparent relatively small economic difference between achieving 2.0 ppm and 2.5 ppm (depending upon the assumptions used), MCESD and USEPA have required Duke, as a federally enforceable condition, to participate in a 2-year demonstration period, whereby the federally enforceable limit is 2.0 ppm, 3-hour average for the first two years of operation, but Duke must strive to consistently meet 2.0 ppm, 1-hour average. In addition, as a result of its agreement with the Arizona Corporation Commission, Duke is required to meet a 2.0 ppmvd, 1-hour average as a locally enforceable permit condition. The locally enforceable 2.0 ppm, 1-hour average remains in place regardless of the results of the 2-year demonstration period. If Duke consistently meets the 2.0 ppm, 1-hour average, then that limit will also become federally enforceable at the end of the 2-year demonstration period. However, if the Permittee can demonstrate to the satisfaction of the Control Officer and Administrator that the facility has not been able to reasonably and consistently meet the 2.0 ppm, 1-hour limit, and the Permittee submits in writing a demonstration seeking a change from the 2.0 ppm 1-hr to a suggested new limit, the Control Officer and the Administrator shall set a new NOx limit if the demonstration is acceptable.

In light of the fact that Duke must meet the 2.0 ppm limit as a locally enforceable condition and the fact that the 2.0 ppm 1-hr average, automatically becomes federally enforceable at the end of the 2-year demonstration period unless Duke can demonstrate to the satisfaction of the Control Officer and Administrator otherwise; no minimum ammonia injection rate monitoring requirement was placed on AVEF II. Unlike AVEF I, the most stringent limit automatically applies to AVEF II unless demonstrated otherwise.

J.6 Engineering Cost Analysis for CO

The only other system for CO control other than a CAT-OX as proposed by Duke is the SCONOX system, which removes CO and NO_x through the same process. The SCONOX system was demonstrated to not be cost effective for NO_x control and is, therefore, also not cost effective for CO control. More importantly, the SCONOX has not been demonstrated technically feasible for large combustion turbine systems.

J.7 Other Agency Permitting Decisions for CO

As in the case of NO_x control, the most recent permitting decisions were evaluated to determine the BACT limit with a CAT-OX system. Again, the Clearinghouse data were dated and the permitting decisions were considered as precedent over the Clearinghouse data.

The Arizona agency permitting decisions for combustion turbine systems with CAT-OX were one unit at 10 ppmvd 3-hour, two units at 4 ppmvd 3-hour, and one unit at 2.8 ppmvd 24-hour. The 2.8 ppmvd 24-hour average limit was a unique situation. Therefore, Arizona permitting decisions have clustered around the 4 ppmvd, 3-hour average limit. However, the duct burners at these units were about one-half the size of the AVEF II duct burners.

Other agency permitting decisions have ranged from 10 ppmvd 3-hour or greater in Nevada, 4 ppmvd or greater in California, to 2 ppmvd 1-hour in Washington state. However, the 2 ppmvd, 1-hour permit limit was to avoid a regulatory threshold and that unit has not been built. Again, the duct burners on the Washington facility are about one-half the size of the AVEF II duct burners.

J.8 Permit Emission Limits for CO from AVEF II

Despite the fact that Duke proposed 4 ppmvd 3-hour average as an overall limit (with or without duct burners), MCESD established a dual permit limit of 2 ppmvd 3-hour without duct burners and 4 ppmvd 3-hour with duct burners. Since there is no limit on the number of hours that duct burners can be used, the annual emission limits are based on 100% duct burner use.

J.9 Permit Emission Limits for VOC

VOC control is achieved through the CAT-OX and low NO_x burners operated within good combustion practices. The USEPA suggests that CO emission limits can be used as a surrogate for efficient control of VOCs since the catalytic oxidation of CO also results in oxidation of VOCs. Duke initially proposed a VOC permit limit of 1 ppmvw 3-hour average without duct burners and 6 ppmvw 3-hour average with duct burners and later suggested 1 ppmvd 3-hour average without duct burners, and 4.0 ppmvd 3-hour average with duct burners (for consistency, Duke proposed to state all emission limits corrected to “dry, 15% oxygen”). MCESD is not aware of lower permit limits for VOC from large combustion turbines, and accepted the proposed limits.

J.10 Summary of Permitted Emission Limits for the Combustion Turbine System at BACT

Table 6-1 provides a summary of the BACT permit limits for the AVEF II Combustion Turbine Systems.

Table 6-1

AVEF II Permit Limits at BACT

Pollutant	BACT Technology	BACT Limits
NO_x	SCR with Low NO_x combustors	2.0 ppmvd at 15% O_2, 3-hour average with or without duct burners, during a 2-year demonstration period, but defaulting to 2.0 ppmvd, 1-hour average at 15% O_2 at the end of the demonstration unless the Permittee demonstrates that 2.0 ppm, 1-hour is not achievable.
CO	CAT-OX	2.0 ppmvd at 15% O_2 without duct burners, 3.0 ppmvd at 15% O_2 with duct burners
VOC	CAT-OX	1.0 ppmvd at 15% O_2 without duct burners, 4.0 ppmvd at 15% O_2 with duct burners
PM_{10}	Good combustion practices and natural gas fuel only	9 lb/hr per unit Method 5, 18 lb/hr per unit Method 5 plus 202 with duct burners off. 25 lb/hr Method 5 plus 202 with duct burners on.
SO_2	Good combustion practices and commercial quality natural gas fuel	0.0075 grains per scf

K. Locally Enforceable Limits for the AVEF II Combustion Turbine Systems

Under an agreement with the Arizona Corporation Commission (ACC), Duke has agreed to voluntarily install controls that are equivalent to the lowest achievable emissions rate levels on the CTGs. The lowest achievable emission rate is generally more stringent than BACT, since energy, economic, environmental and other costs cannot be considered for the lowest achievable rate. To determine the lowest achievable emission rate, the previously cited data bases used to determine BACT were again evaluated to determine the most stringent level of control that meets the definition of LAER. The primary database used to determine the lowest achievable emission rate for NOx, CO, and VOC was recent permitting decisions by the South Coast Air Quality Management District (SCAQMD) and the California Energy Commission. The primary database used to determine the lowest achievable emission rate for PM_{10} was recent permitting decisions by Maricopa County Environmental Services Department, Clark County Department of Air Quality Management, other agency permits, and source test data provided by Duke.

K.1 Locally Enforceable Limits for the AVEF II Combustion Turbine NO_x Emissions

The most stringent NOx emission limit that has recently been permitted for CTGs is 2.0 ppmvd, 1-hour average. There is one unit permitted in Massachusetts that has a dual 1.5 ppmvd/2.0 ppmvd limit, however that unit does not have duct burners. As stated previously, the duct burners contribute a significant amount of NO_x. Therefore, 2.0 ppmvd, 1-hour average was considered equivalent to the lowest achievable emission rate for NO_x, achieved with an SCR system.

Emission rates achieved by SCONOX are not considered to be the lowest achievable emission rate since it has not been demonstrated and the SCONOX emission guarantee is the same as what can be achieved with the demonstrated SCR systems.

K.2 Locally Enforceable Limits for the AVEF II Combustion Turbine CO Emissions

A review of the various databases and recent permitting decisions indicate that CO emission limits are more variable, with a range of CO emission limits from 2 to 10 ppmvd at various averaging times for units with duct burners. The most relevant recent permitting decision was the lowest achievable emission rate for the Copper Mountain power plant that has a duct burner approximately the same size as AVEF II and the Santan Generating Station in Maricopa County. Copper Mountain was permitted at 3.0 ppmvd, 3-hour average and Santan at 2.0 ppmvd, 3-hour average. Therefore, 2.0 ppmvd, 3-hour average was selected as the lowest achievable emission rate, achieved with a CAT-OX system.

Again, SCONOX was eliminated as it has not been demonstrated and does not yield emission limits significantly less than the CAT-OX level proposed.

K.3 Locally Enforceable Limits for the AVEF II Combustion Turbine VOC Emissions

VOC emissions limits are even more variable than CO emission limits, but range from 1 to 2 ppmvd for units without duct burners, and the Santan Generating Station was permitted by Maricopa County at 2.0 ppmvd with duct burners on. Accordingly, a 1.0 ppmvd VOC emission limit with duct burners OFF and 2.0 ppmvd with duct burners ON was selected as the lowest achievable emission rate. Again, this will be achieved through a CAT-OX.

K.4 Locally Enforceable Limits for the AVEF II Combustion Turbine PM Emissions

Good combustion practices, and restriction to use only natural gas fuel with limited sulfur content is considered the lowest achievable emission rate throughout the industry. If the CO, NO_x, and VOC emissions are limited through good combustion practices (plus post-combustion controls), the PM emissions will also be limited. SCAQMD permitting decisions for the lowest achievable emission rate are consistently 0.01 grain per dry standard cubic foot. This translates to about 160 pounds per hour for AVEF II. Although this is much higher than the level proposed by Duke of 25 pounds per hour, additional information was reviewed to see if lower PM_{10} emission rates have been achieved in practice. For this review, other recent permitting decisions for comparable facilities and source test data from similar types of facilities were reviewed. This review found that most permits are issued at emission rates equivalent to about 0.008 lb/mmBtu and several permits were issued at 0.010 lb/mmBtu. There appear to be a few unrepresentative cases where the applicant accepted an unreasonably low limit in order to reduce impacts or avoid other regulatory requirements such as offsets. These unrepresentatively low limits have not been demonstrated (they are permitted or proposed permitted only). Therefore, since it appeared that the lowest emission rate consistently permitted as LAER by other agencies was based on about 0.008 lb/mmBtu, that level was chosen as the lowest achievable emission rate for AVEF II. The review of source test data showed that a wide range of PM_{10} emissions levels have been observed, but an overall level of about 0.008 lb/mmBtu appeared to have been achieved in most cases. Accordingly, 19 pounds per hour with duct burners on (equivalent to about 0.008 lb/mmBtu) was selected as the lowest achievable emission rate for each of the AVEF II combustion turbines. There are no post-combustion controls for PM from combined cycle systems.

K.5 Locally Enforceable Limits for the AVEF II Combustion Turbine SO_2 Emissions

SO_2 emissions are limited by limiting the amount of sulfur that can be in the natural gas. The AVEF II permit requires Duke to use only commercially available pipeline quality natural gas with an SO_2 content less than 0.75 grains per 100 standard cubic feet. There is no post-combustion controls available for SO_2 from combined cycle systems.

K.6 Locally Enforceable Limits for the AVEF II Cooling Tower

MCESD also undertook a review of the lowest droplet drift rates that have been proposed, permitted or achieved. This review indicated that the 0.0005% drift rate selected as BACT was also the lowest drift rate achievable. There is some discussion that a single cooling tower vendor may be able to build a 0.0003% drift rate tower. However, the vendor stated that this tower is a non-standard design and has not been built (and accordingly, has not yet been able to demonstrate that 0.0003% is achievable). Accordingly, the 0.0005% rate was selected as the lowest achievable rate for the AVEF II cooling tower.

K.7 Summary of Locally Enforceable Permitted Emission Limits for the Combustion Turbine System

Table 6-2 provides a summary of the locally enforceable permit limits for the AVEF II Combustion Turbine Systems.

Table 6-2
AVEF II Locally Enforceable Permit Limits

Pollutant	Control Technology	Locally Enforceable Limits
NO_x	SCR with Low NO_x combustors	2.0 ppmvd at 15% O_2, 1-hour average with or without duct burners
CO	CAT-OX	2.0 ppmvd at 15% O_2, 3-hour average with or without duct burners
VOC	CAT-OX	1.0 ppmvd at 15% O_2 without duct burners, 2.0 ppmvd at 15% O_2 with duct burners
PM_{10}	Good combustion practices and natural gas fuel only	9 lb/hr per unit Method 5, 15 lb/hr per unit Method 5 plus 202 with duct burners off. 19 lb/hr Method 5 plus 202 with duct burners on.
SO_2	Good combustion practices and commercial quality natural gas fuel	0.0075 grains per scf

L. BACT for the Auxiliary Boiler

Duke is proposing to operate the AVEF II auxiliary boiler (rated at 33 mmBtu/hr, higher heating value, 105% load) up to 6,000 hours per year. The facility-wide emission limits include the potential to emit from the auxiliary boiler at 100% load for 6,000 hours per year, even though it is anticipated that the boiler will be utilized at much less than 100% load most of the time. (Duke states that typically the auxiliary boiler will operate at 20% load.) The emissions included in the facility-wide limits are 3.3 tpy NO_x and 14.1 tpy CO based on 6,000 hours per year at 105% load. These amounts are less than 3% of the facility-wide emissions.

In order to determine the BACT level for the auxiliary boiler NO_x and CO, eight data sources were considered:

- Boiler vendor information
- Previous Pima County, Pinal County, Arizona State permitting decisions
- Previous Maricopa County permitting decisions
- California Air Pollution Control Officers (CAPCOA) BACT Clearinghouse
- RACT/BACT/LAER Clearinghouse (RBLC)
- Engineering cost analysis
- South Coast Air Quality Management District (SCAQMD) BACT Manual
- San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) Rule 4305

These data sources were recommended by the USEPA and have been used in previous Maricopa County permitting decisions.

L.1 Boiler Vendor Information

Duke contacted several boiler vendors before selecting Cleaver Brooks to provide the boiler. The vendor guaranteed an emission limit of 0.035 lb/mmBtu NO_x and 0.150 lb/mmBtu CO. These emission limits will be met through low NO_x burners and flue gas recirculation (LNB-FGR).

L.2 Previous Agency Permitting Decisions

Review of Pima County, Pinal County, Arizona State, Maricopa County permitting decisions indicate that boilers smaller than 100 mmBtu/hr have had no more stringent control technology required than low NOx burners and flue gas recirculation (LNB-FGR) for NO_x and CO control.

Review of the CAPCOA Clearinghouse indicated that agencies have required boilers smaller than 100 mmBtu/hr to be fitted with LNB alone, LNB-FGR, LNB plus selective catalytic reduction (SCR), or ultra-Low NO_x Burners (ULNB) for NO_x control. No post combustion CO control was identified for boilers less than 100 mmBtu/hr.

L.3 Engineering Cost Analysis

L.3.1 NO_x Control Technology

In order to provide a complete BACT analysis, Duke provided engineering cost analyses for the cost of NO_x control using ULNB, SCR, and SCONOX. The baseline costs were assumed to be LNB-FGR as proposed. Duke demonstrated that the cost of ULNB was approximately $10,800 per total ton removed (at 100% load for 6,000 hours), SCR was about $26,100 per total ton removed, and SCONOX was about $43,300 per ton removed. The high cost of SCR and SCONOX and the fact that these systems have not heretofore been required for auxiliary boilers at combined cycle power plants eliminates those technologies from further consideration.

The cost of ULNB is likewise quite high. However, in addition to the cost issue, there is a technical feasibility issue, because ULNB boilers can operate only within a very narrow load factor (typically no more than a 4:1 turn down ratio). A small turn down ratio is acceptable for process heat boilers. On the other hand, Duke will need to operate the auxiliary boiler at turn down ratios of 10:1. These larger turn down ratios are required when boilers are used in combined cycle power plants because their use is simply to keep the turbines and other equipment warm. This technical issue in addition to the cost issue eliminates ULNB from consideration.

L.3.2 CO Control Technology

Duke examined the cost of installing an oxidation catalyst on the auxiliary boiler in order to control CO as well as the SCONOX system. As indicated, the SCONOX system is very expensive and has been eliminated. The ULNB system has also been eliminated for cost and technical feasibility reasons. The cost of an oxidation catalyst to control CO is approximately $5,000 per total ton removed (at 100% load for 6000 hours), but the oxidation catalyst technical feasibility is also questionable considering the large turn down ratio requirement.

Note that the cost figures for both NO_x and CO were derived assuming 100% load for 6,000 hours (i.e., the tons removed were calculated based on full load emissions). However, in practice, the auxiliary boiler will probably only operate at 20% load, thus increasing the cost per ton removed by a factor of five.

L.3.3 Selected NO_x and CO Control Technology

Based on the above technical feasibility and cost analysis, the LNB-FGR control technology was selected. Accordingly, the remainder of this analysis focuses on the lowest feasible emission limits using the LNB-FGR technology. To confirm that Duke's proposed emissions limits are the lowest that can be achieved with LNB-FGR technology, the RBLC database, the SCAQMD BACT Manual, and SJVUAPCD Rule 4305 were reviewed.

L.4 NO_x Emission Limits for LNB-FGR Technology

Duke provided a detailed summary of the RBLC data available as of November 1, 2001 for boilers rated at less than 100 mmBtu/hr. Typically, data in the RBLC database are quoted in parts per million by volume dry (ppmvd) rather than lb/mmBtu. In addition, when lb/mmBtu are quoted, it is not certain if the emission rate is based on higher heating value or lower heating value natural gas heat content. When Duke converted the ppmvd data in the RBLC to lb/mmBtu, they used higher heating value, but did not correct for percent oxygen. Typically, boiler emission rates in ppmvd are provided corrected to 3% oxygen. Therefore, not correcting for percent oxygen introduces about a 15% difference in converted emission rates. For example, a 30 ppmvd NO_x emission limit is equivalent to 0.030 lb/mmBtu when no correction for percent oxygen is included, but 0.036 lb/mmBtu when the correction for 3% oxygen is made. As stated, typically boiler emission limits are specified at 3% oxygen, so converting without considering the oxygen content yields incorrect values. Therefore, for purposes of this analysis, it is assumed that an RBLC converted value of 0.030 lb/mmBtu presented by Duke (i.e., without the oxygen correction) is equivalent to 0.036 lb/mmBtu (corrected to 3% oxygen).

In the RBLC database, there were 22 units that used LNB and/or FGR and had NO_x emission limits specified. Of these 22 units, only 2 had emission limits less than 0.035 lb/mmBtu (corrected to 3% oxygen, or 0.030 lb/mmBtu without correction). These two units were a 2 and 16.5 mmBtu boiler used at a California correctional facility. These small boilers are not considered representative of Duke's 33 mmBtu/hr boiler.

The SCAQMD BACT Manual was also reviewed as part of the analysis. However, the SCAQMD Manual lists ULNB as the default technology. Since ULNB is not technically or cost feasible for Duke's purposes, the SCAQMD Manual emission limits are not relevant.
The SJVUAPCD Rule 4305 specifies a BACT level for boilers greater than 30 mmBtu/hr. The Rule applies to boilers in any application. Section 5.1 of the SJVUAPCD Rule 4305 specifies NO_x emission limits of 30 ppmvd or 0.036 lb/mmBtu. In addition, recent permitting decisions in Maricopa County for process boilers were 30 ppmvd at 3% oxygen.
Accordingly it is concluded that a NO_x emission limit of 0.035 lb/mmBtu as proposed by Duke is BACT for the auxiliary boiler.

L.5 CO Emission Limits for LNB plus FGR Technology

Of the 22 units in the RBLC database with NO_x limits specified and using LNB and/or FGR technology, only 8 units had associated CO limits. Of these 8 units, 2 had CO limits greater than the 0.150 lb/mmBtu proposed by Duke. Of the remaining six units, only four were greater than 20 mmBtu/hr. The NO_x limits for these four units were 0.070, 0.105, 0.104, and 0.058 lb/mmBtu (when corrected to 3% oxygen). However, all four of these boilers are process boilers, and three of the boilers had NO_x limits greater than the BACT for NO_x of 0.035 lb/mmBtu. There is a trade off between NO_x and CO (as NO_x emissions decrease, CO emissions tend to increase). In addition, when a boiler is used in the Duke configuration (with a large turn down ratio), it is more difficult to control both NO_x and CO. The only boiler in the RBLC database with NO_x limit as low as 0.035 lb/mmBtu and an associated CO limit had a CO limit of 0.104 lb/mmBtu. This was a 31.2 mmBtu/hr process boiler.

The SJVUAPCD Rule 4305 limits for CO are 400 ppmvd (at 3% oxygen), which converts to 0.295 lb/mmBtu, nearly twice the limit being proposed by Duke. The SCAQMD BACT Manual again lists ULNB as the default technology, which is not relevant for determining LNB plus FGR emission limits. Recent permitting decisions in Maricopa County have been at the 400 ppmvd (i.e., 0.295 lb/mmBtu) level. Duke has obtained a vendor guarantee for CO limits of 0.150 lb/mmBtu. Based on the data in the RBLC database, the SJVUAPCD Rule 4305, and recent Maricopa County permitting decisions, the proposed 0.150 lb/mmBtu CO limit is considered BACT.

M. BACT for the Cooling Tower

Duke is proposing an eight-cell wet cooling tower for AVEF II. The cooling tower will have a water recirculation rate of 180,000 gallons per minute (gpm) for all 8 cells, or 22,500 gpm per cell. The total dissolved solids (TDS) content of the cooling tower water will be limited to 12,000 milligrams per liter (mg/l). Initially Duke proposed a water droplet drift rate of 0.001%, but later revised the drift rate to 0.0005% to be consistent with state of the art towers and recent permitting decisions.

Emissions of PM_{10} from the cooling tower are difficult to estimate as the emission rate is a function of not only the drift rate and TDS content, but also the droplet size distribution. Duke provided representative droplet size distribution data and estimated that the fraction of drifted TDS that condenses to particles of mean aerodynamic diameter of 10 microns or less (i.e., PM_{10}) would be 15% or less. However, since the PM_{10} fraction is significantly dependent upon the actual droplet size distribution, and since MCESD has recently permitted at least one plant assuming a 31.5% PM_{10} fraction, the 31.5% PM_{10} fraction will be used for permitting and ambient impact assessment purposes. Assuming a 31.5% PM_{10} fraction, 12,000 mg/l TDS, and 180,000 gpm recirculation rate, and 0.0005% drift rate; the PM_{10} emissions are 1.70 pounds per hour (lb/hr) and 7.5 tons per year (tpy) based on 8,760 operating hours per year. These amounts are approximately 3% of the total AVEF II facility emissions.

In order to determine the BACT level for the cooling tower PM_{10}, six data sources were considered:

- Cooling tower vendor information
- Previous Pima County, Pinal County, Arizona State permitting decisions
- Previous Maricopa County permitting decisions
- California Air Pollution Control Officers (CAPCOA) BACT Clearinghouse
- RACT/BACT/LAER Clearinghouse (RBLC)
- Engineering cost analysis

These data sources were recommended by the USEPA and have been used in previous Maricopa County permitting decisions.

M.1 Cooling Tower Vendor Information

Duke contacted several cooling tower vendors to determine the best drift rate that could be obtained. An initial vendor provided a drift rate guarantee of 0.001%, but later vendor contacts identified a drift rate of 0.0005%.

The water recirculation rate is a function of the amount of heat that must be rejected from the steam turbine exhaust, the combustion turbines, and the steam turbine's generator and lube oil cooling. Since Duke proposes a combined cycle facility that attempts to extract the maximum amount of energy from the fuel (i.e., high efficiency), the amount of rejected heat is minimized.

The maximum TDS level of the water in the cooling tower is limited as a practical matter since too high of a TDS will result in cooling tower system corrosion and fowling. The minimum TDS is limited by excessive water usage (and commensurate increase in evaporation pond sizes). If the TDS is too low, the amount of water used increases significantly.

M.2 Previous Agency Permitting Decisions

Review of Pima County, Pinal County, Arizona State, Maricopa County permitting decisions indicate that cooling towers with a 0.0005% drift rate are the best controlled towers permitted.

The TDS and recirculation rate proposed by Duke are consistent with other recent power plant permits.

Review of the CAPCOA Clearinghouse and the RBLC database did not reveal a power plant-sized cooling tower with a drift rate less than 0.0005%. However, it has been noted that two plants in California and one in Nevada have been permitted with dry cooling instead of wet cooling towers. The dry cooling towers at these three plants apparently also use a minimal amount of water for supplemental wet spray assistance during the higher temperature days. The western U.S. plants permitted or known to have dry cooling (with wet spray assistance) are the 240 MWe Crockett Cogeneration plant (permitted in 1993 and on-line in 1996), the 540 MWe Calpine Sutter plant (permitted in November, 1999 and not yet on line), and the 580 MWe Moapa plant in Nevada (permitted in 2001 and not yet on line).

The advantage of dry cooling towers is that PM_{10} emissions are minimized and water use and land use for evaporation ponds and/or water disposal to a sanitary sewer are minimized. The disadvantage of dry cooling is that the systems are expensive and result in a facility energy penalty due to the large fans that must be used in the dry cooling towers. The dry towers tend to also be very large systems compared to wet cooling towers. Although no Arizona plants have been permitted with dry cooling and only three plants in the western US are known to be permitted with dry cooling, an engineering cost analysis was performed to determine the cost-benefit of dry versus wet cooling.

M.3 Engineering Cost Analysis

In order to provide a complete BACT analysis, Duke provided an engineering cost analysis comparing the cost of 100% dry cooling (without water spray assistance) to 100% wet cooling. The cost factors analyzed by Duke are shown in Table 6-3 and the cost analysis is shown in Table 6-4.

Table 6-3
Factors for Determining Cooling Tower Costs Presented by Duke

Factors	Applicability to AVEF II
Capital cost of civil works infrastructure to transport water to the plant site	Local groundwater will be used so no off-site water pipeline construction will be needed. Additionally, since AVEF II is an expansion of AVEF I, much of the water infrastructure will be in place from AVEF I project.
Capital and energy production difference between facilities equipped with wet cooling tower and dry cooling system.	Capital and energy loss costs for the wet cooling tower and condensing plant and the dry cooling tower were obtained from Thermoflow's GTPro power plant design program. The difference in the capital cost between the two tower configurations was calculated to determine the incremental cost.
Cost to pump energy to move water to plant site	Water supply for AVEF will be drawn from ground water thus no long distance water transportation infrastructure is required.
Cost to pump energy from ground to the tower	No site-specific data on pumping costs were available. This cost has been incorporated into the AVEF II cost analysis by including the water supply as indicated in the permit application.
Cost of raw water and raw water treatment	GTPro was used to determine the amount of water used in the makeup and blowdown streams of the wet mechanical tower. Although ground water will be used for this project and supply and treatment costs will be relatively low, typical water supply and treatment as indicated in the permit application were used to represent a worst case cost estimate. Powers provided a relatively high cost of raw water at $2 per 1000

	gallons and discharge water disposal (based on sanitary sewer costs) of \$3 per 1000 gallons.
Water treatment solids disposal	This cost has been incorporated into the AVEF II cost analysis.
Cooling tower blowdown solids generation and disposal	This cost has been incorporated into the AVEF II cost analysis.
Cost of lost energy	GTPro was used to determine the loss of power due to increased back pressure in the dry cooling tower.

Table 6-4
Engineering Cost Analysis Presented by Duke for Comparing Dry to Wet Cooling

	Item	Notes	Annual Average	Summer Average	Winter Average
Ambient temperature [F]		1	66.3	88.3	62.7
Dry Cooling					
Plant net output [kW]	A	2	564,875	521,098	571,471
User-defined Total Costs [kUSD]	B	3	$ 280,461	$ 279,071	$ 280,383
Annual Water Costs [kUSD/yr]	C				
PM_{10} Emissions [lb/hr]	D		0.00	0.00	0.00
Wet Mechanical					
Plant net output [kW]	E		575,739	535,241	581,957
User-defined Total Costs [kUSD]	F	4	$ 259,286	$ 248,953	$ 260,478
Annual Water Costs [kUSD/yr]	G	5	$3,390	$ 3,390	$ 3,390
Incremental Change (compared to wet mechanical)					
Annual Power Difference [kW/yr]	H	6	-10,864	-14,143	-10,486
Annual Cost of Lost Power [kUSD/yr]	I	7	$ 3,331	$ 4,336	$ 3,215
Total Capital Costs [kUSD]	J	8	$ 21,175	$ 30,118	$ 19,905
Annualized Capital Costs [kUSD/yr]	K	9	$ 1,707	$ 2,428	$ 1,604
Annual Operation Costs [kUSD/yr]	L	10	$ -59	$ 947	$-175
Total Annual Costs [kUSD/yr]	M	11	$ 1,648	$ 3,374	$ 1,430
Emission Summary					
PM_{10} Controlled [lb/hr]	N	12	1.70	1.70	1.70
PM_{10} Controlled [tons/year]	O	13	7.46	7.46	7.46
PM_{10} Cost Effectiveness [$/ton controlled]	**P**	**14**	**$ 220,775**	**$ 452,032**	**$ 191,534**

Notes:

1. There are different runs for different temperatures since the energy penalty is a function of ambient temperature.
2. (1-e/a) = % energy penalty. Penalty is 1.9% annual, 2.7% summer, and 1.8% winter.
3. This is an estimate of total capital cost based on the GTPro engineering software, provided by Duke in the permit application supplement.
4. This is an estimate of total capital cost based on the GTPro engineering software, provided by Duke in the permit application supplement.
5. (2478 gpm x 8760 hr/yr x 60 min/hr x \$2/1000 gal makeup water) + (496 gpm x 8760 hr/yr x 60 min/hr x \$3/1000 gal blowdown water) = \$3,390,000.
6. e - a
7. h x 8760 x \$ 0.035 per kilowatt-hour.
8. b - f
9. (0.081 x j) Capital cost recovery factor = 0.081. Based on 30-year lifetime, 7% interest rate.
10. i - g
11. k + l
12. 31.5% PM_{10} fraction, 0.0005% water droplet drift rate.

13. Based on 8760 hours of operation per year.
14. m divided by o

Table 6-4 shows that the cost per ton removed of particulate is extremely high for dry cooling, ranging from about $200,000 per ton removed to nearly $500,000 per ton.

However, other engineering analyses have used considerably different numbers and assumptions. A sensitivity analysis indicated that even if significantly more conservative assumptions are made, the analysis shows that dry cooling is not cost effective.

M.4 PM_{10} Emission Limits for the Cooling Tower

BACT was determined to require a maximum water droplet drift rate of 0.0005%. Duke provided data to show that the PM_{10} fraction could be 15% or less. However, recent MCESD permits have used a 31.5% assumption. Therefore, the permit emission limit (and associated impact modeling) was based on a 31.5% PM_{10} fraction. The cooling tower will operate at a maximum of 12,000 mg/l TDS, and 180,000 gpm recirculation rate. The PM_{10} permit limit is calculated as follows:

180,000 gpm x 12,000 mg/l x 60 min/hr x 1 g/1000 mg x 1 lb/453.6 g x
3.785 l/gal x 0.000005 x 0.315 = **1.70 lb/hr**

1.70 lb/hr x 8760 hr/yr x 1 ton/2000 lb = **7.5 tons/yr**

The permit limit is for all eight cooling tower cells combined for AVEF II.

N. SO_2 Emissions from the AVEF I and AVEF II Combined Cycle Systems and the AVEF I and AVEF II Auxiliary Boiler

AVEF I and II will use only natural gas fuel in the Combined Cycle Systems and Auxiliary Boiler. The sulfur content of the natural gas will be limited to 0.75 grains per 100 standard cubic feet, consistent with pipeline quality natural gas. The sulfur content will be monitored on a custom schedule acceptable to the USEPA and MCESD as described in the Permit.

Although SO_2 is not emitted in levels above BACT thresholds, the sulfur content limits on natural gas fuel and the use of natural gas only is consistent with BACT for SO_2.

O. PM_{10} and SO_2 from the AVEF I and II Diesel-Fueled Engines

To aide in particulate and SO_2 control from the diesel-fueled engines, sulfur content in the diesel fuel will be limited to 0.05% by weight and verified by the fuel supplier.

P. Ammonia Emissions from AVEF I and AVEF II

As part of the BACT analysis, pollutants in addition to the criteria pollutants were examined. In none of the BACT decision cases were non-criteria pollutant emissions relevant for the BACT decision except for the SCR systems, which uses ammonia to control NO_x emissions. Some of the ammonia used in the SCR systems will be emitted unreacted from the system. This is termed ammonia slip. The unreacted ammonia in the SCR exhaust has the potential to react downstream of the SCR or in the atmosphere with SO_2 in the exhaust to create additional particulate. In addition, unreacted ammonia in the atmosphere has the potential to cause direct health effects (which are evaluated in Arizona through the AAAQG program). On the other hand, if insufficient ammonia is used, there is a possibility that the SCR emission control will not be as effective as it could be. Therefore, the permit includes a minimum ammonia injection rate requirement for AVEF I (Appendix D) and a maximum ammonia injection rate for both AVEF I and II.

Ammonia slip is permitted at a maximum of 10 ppmvd in the exhaust of each combined cycle system. This level will be confirmed through required annual stack testing and a requirement that whenever the ammonia injection rate associated with 10 ppm ammonia slip (i.e., 340 pounds per hour of 20% ammonia solution per SCR for AVEF I or 436 pounds per hour of 20% ammonia solution per SCR for AVEF II, depending upon the assumed molar ratio of NO to NO_2 – see discussion following) is exceeded, additional stack testing to confirm that the 10 ppm limit is still being met is required.

The 10 ppm ammonia slip level is consistent with the best operating systems. In addition, since the amount of sulfur in the pipeline quality natural gas is relatively low and since only natural gas fuel is used, resultant PM_{10} emissions from ammonia reacting with the SO_2 will be relatively low. Nevertheless, for purposes of PM_{10} impact assessments, it has been assumed that all of the ammonia reacts to create additional PM_{10}. For purposes of AAAQG assessment, it has been assumed that none of the ammonia reacts. (In this manner, the ammonia is "double counted" with respect to impact assessments). Even with double counting, the AAAQG analysis showed that ambient ammonia concentrations would be less than 4% and 1% of the 1-hour and 24-hour AAAQGs, respectively.

Since there is not a continuous emission monitoring system available for ammonia, the ammonia slip limit will be met by establishing an ammonia injection rate above which source testing will be required to confirm that the ammonia slip limit is being met.

The ammonia injection rate associated with a 10 ppmvd ammonia slip limit can be calculated by determining the amount of ammonia necessary to react with the amount of NO_x produced in the duct burners and combustion turbine, assuming a molar ratio for the reaction of NO_x and NH_3, and adding the equivalent mass of NH_3 corresponding to 10 ppmvd (corrected to 15% oxygen). At maximum combustion of the combustion turbine and duct burner combined, each AVEF I Combined Cycle System will generate (uncontrolled) 89 pounds per hour of NO_x (as NO_2), which is equivalent to 1.934 moles of NO_2 per hour. Each AVEF II Combined Cycle System will generate uncontrolled 115.3 pounds per hour of NO_x (as NO_2), which is equivalent to 2.506 moles per hour. Controlled emissions from AVEF I at the minimum emission rate of 2.5 ppmvd (i.e., the rate that requires the most ammonia) is 20 lb/hr from each unit with duct burners on. Controlled emissions from AVEF II at the minimum emission rate of 2.0 ppmvd is 17.8 lb/hr from each unit with duct burners on. Therefore, 69 pounds per hour (89 – 20 = 69) of NO_2 must be reacted in AVEF I (1.50 moles) and 97.5 pounds of NO_2 (115.3 – 17.8 = 97.5) must be reacted in AVEF II (2.12 moles).

The ammonia slip for both AVEF I and II is the same, 10 ppmvd. However, because AVEF II is slightly larger, the mass of ammonia associated with 10 ppmvd slip is different, 29.7 lb/hr for AVEF I and 34.0 lb/hr for AVEF II.

NO_x emissions from natural gas combustion normally consist mostly (95%) of NO versus NO_2. However, it is anticipated that emissions from the dry low NO_x combustion turbines will have a larger percentage of NO_2 because of the reduced flame temperature, reduced residence time and lean fuel mixture. The percentage of NO may be as low as 10% (with NO_2 being 90%). The stoichiometry for the reaction of ammonia with NO is different than with NO_2, being one mole of NH_3 for one mole of NO, but two moles of NH_3 for one mole of NO_2. Therefore, the amount of ammonia needed for reaction is a function of the amount of NO versus NO_2.

In order to account for the uncertainty in the relative percentage of NO and NO_2, the permit contains a formula that depends upon the molar ratio of NH_3 to NO_x. An initial default ratio of 1.50 is assumed (corresponding to 50% NO and 50% NO_2 in the exhaust), but with adjustments to the ratio determined by actual stack emissions or other emissions data from the Combined Cycle Systems.

With a molar ratio of 1.50, the amount of pure ammonia (NH_3) that can be injected into each AVEF I SCR system is 68.0 pounds per hour (29.7 + 1.50 moles of NO_2 reacted * 17.034 lb-mole ammonia * 1.5 moles ammonia per mole of NO_2 = 68) and for each AVEF II SCR system is 88.2 pounds per hour (34.0 + 2.12 moles NO_2 reacted * 17.034 lb-mole ammonia * 1.5 moles ammonia per mole of NO_2 = 88.2) when the duct burners are on. If the molar ratio decreases to 1.05 the amount of pure ammonia injected into each AVEF I SCR system would be 56.5 pounds per hour and each AVEF II SCR system would be 71.9 pounds per hour when the duct burners are on. If the ratio increases to 1.90, the pure ammonia injection rate for each AVEF I SCR would be 78.2 pounds per hour and each AVEF II SCR system would be 102.6 pounds per hour.

Both AVEF I and II plan to use 20% aqueous ammonia rather than anhydrous ammonia. The trigger rate is based on the amount of ammonia, not aqueous ammonia. For example, if 20% aqueous ammonia is used for AVEF II, at a molar ratio of 1.5, the trigger for aqueous ammonia would be 441 pounds per hour of aqueous ammonia (441 lb/hr aqueous ammonia x 0.20 ammonia fraction = 88.2 lb/hr ammonia).

Q. Other Hazardous Air Pollutant (HAPs) Emissions from AVEF I and AVEF II

There are a number of different HAPs that are potentially emitted, and there are a number of different sources of emission factors for each HAP that can be used to estimate the emissions. For the AVEF I initial application, Duke used the USEPA AP-42 emission factors for the metals and the California CATEF II database (current as of April, 2000) for the remaining HAPs (essentially VOCs). With the AVEF II submittal, Duke substituted a site-specific emission factor for AVEF I hexane and formaldehyde. For AVEF II Duke used the USEPA AP-42 emission factors supplemented by the California CATEF II database (dated January 2001) for the combustion turbine emission factors, except for formaldehyde and hexane. The AVEF II hexane and formaldehyde emission factors were calculated site-specific values. Since there is no CAT-OX on AVEF I, the emission factors were used assuming no emission control. However, since AVEF II has a CAT-OX that provides VOC emission control as well as CO control, a HAP control efficiency of 32% was assumed.

The uncontrolled and controlled HAPs emissions from AVEF I and II are a total of 21.2 tons per year (tpy) aggregate with no HAP greater than 10 tpy (the maximum is formaldehyde at 6.85 tpy).

Since there is considerable uncertainty regarding the emission factors and control efficiency of the CAT-OX, emissions testing to confirm the HAPs emission limits is required in the permit and HAP emissions are limited to 22.5 tpy aggregate, 9 tpy maximum individual, to provide a margin of safety related to the major HAP source thresholds of 25/10 tpy aggregate/individual HAPs.

Although there are a large number of individual HAPs that have been reported to be emitted from natural gas fueled combustion turbine systems, stack testing is required in the permit for only the six volatile organic HAPs with the largest emission factors. The six largest volatile organic HAPs (acetaldehyde, toluene, xylene, ethylbenzene, hexane, and formaldehyde) have emission factors at least ten times greater than the next lowest emission factor and are responsible for approximately 90% of the total HAPs emissions. (Propylene oxide has an apparently high emission factor, but AP-42 indicates that propylene oxide has not been detected; therefore, the propylene oxide emission factor is an artifact of the detection limit, and propylene oxide emission testing is not required). The six compounds for which stack testing is required is consistent with other MCESD permits.

R. Source Emissions Testing and Continuous Emissions Monitoring

In order to confirm that the emission limits determined as BACT and as the lowest achievable are indeed met, the permit requires an extensive set of source emissions tests and continuous emission monitors (CEMs) for gaseous pollutants that can be measured with CEMs (e.g., NO_x and CO).

The source emission tests are required at both full load and reduced load conditions with duct burners ON and OFF as appropriate.

One issue that arises when testing combustion turbines is what does "full load" mean. This is due to the fact that the capacity of a combustion turbine varies greatly with atmospheric conditions (e.g., temperature, altitude, humidity, etc.) and whether or not the inlet air stream chillers are operated. On the other hand, during an emissions test, the capacity of the unit will be unambiguous and the value will be available at the control room. The only switchable setting for full load conditions is whether the chillers are ON or OFF. Accordingly, the permit clarifies that "full load" is the unit capacity at the time of the test with the chillers ON. However, since the units cannot operate at reduced load with the chillers, the permit clarifies that reduced load testing is with chillers OFF.

A second issue is that the testing methods may have to be revised at times due to new methods, detection limit, and other issues. For those test methods that are not specifically required by a federal regulation, Maricopa County Rule 270 allows the Control Officer to approve an alternate test method. However, no such local authority exists for federally required tests.

VII. CRITERIA POLLUTANT AIR QUALITY IMPACTS IN ATTAINMENT AREAS

A. Existing Ambient Air Quality Conditions

The portion of Maricopa County where the project is located is currently classified as attainment for all criteria pollutants. Duke first analyzed the ambient air quality impacts of AVEF I alone and then in combination with AVEF II and compared those impacts to the Significant Impact Levels (SILs). If the impacts were below the SILs, the analysis proceeded to the "Additional Impacts Analysis." This is the case since, by definition of the SILs, if the impacts were less than the SILs the source would not cause or contribute to a violation of a national ambient air quality standard (40 CFR 51.165(b)(2)). The SILs are shown in Table 7-1. If the impacts are not less than the SILs, a cumulative impact analysis comparing the cumulative impact of the project and other nearby sources to the NAAQS and PSD increments is required.

Table 7-1
Significant Impact Levels (40 CFR 51.165(b)(2))
(ug/m^3)

Pollutant	1-hour Average	3-hour Average	8-hour Average	24 hour Average	Annual Average
SO_2		25		5	1
PM_{10}				5	1
NO_2					1
CO	2000		500		

In addition, if the impact of the facility is less than the SILs, the impacts will also be less than the PSD increments. The Class I increments are shown in Table 7-2, and the Class II increments in Table 7-3.

Table 7-2
PSD Class I Increments (40 CFR 51.166(c)
(ug/m^3)

Pollutant	3-hour Average	24 hour Average	Annual Average
SO_2	25	5	2

PM_{10}		8	4
NO			2.5

Table 7-3
PSD Class II Increments (40 CFR 51.166(c)
(ug/m^3)

Pollutant	3-hour Average	24 hour Average	Annual Average
SO_2	512	91	20
PM_{10}		30	17
NO_2			25

If the impacts are greater than the SILs, then the cumulative impacts of AVEF I and/or AVEF II with other nearby sources would have to be added to a representative background ambient air quality value and/or pre-construction monitoring would be required if the impacts were greater than the monitoring thresholds of 40 CFR 52.21(i)(8)(i).

B. Climate and Meteorological Conditions

The air quality modeling analysis relies on five years of the most recent, readily available meteorological data (surface observations) from the Palo Verde Nuclear Generating Station (PVNGS). The meteorological station at PVNGS measures winds at 10 and 60 meters above ground level and meets or exceeds the Nuclear Regulatory Commission (NRC) requirements for monitoring instrument specifications, calibrations, and data capture. The NRC requirements are more stringent than PSD requirements, and thus the PVNGS data are useable for the AVEF I and II impacts analysis. PVNGS is at the same elevation as AVEF I and II and is located about 5 kilometers (km) miles north of AVEF I and II, with no intervening high terrain. Therefore, the PVNGS data are representative of AVEF I and II plume dispersion and transport.

The PVNGS five-year data set consisted of observations from 1994 through 1998. These data were combined with upper air data from the Tucson, Arizona National Weather Service upper air station. The USEPA standard methodology for determining mixing heights and processing the meteorological data suitable for input to ISC3 was used to process the Tucson and PVNGS data. USEPA guidance was used for missing data substitutions.

C. GEP Stack Height Analysis

USEPA procedures for determining Good Engineering Practice (GEP) stack height were used to evaluate the proposed stack heights. The GEP stack heights were found to be 185 feet for the Combined Cycle Systems, 118 feet for the cooling tower, and 50 feet for the auxiliary boiler. Duke proposed stack heights of 185 feet for the AVEF I and II Combined Cycle Systems, 47 feet for the AVEF I cooling tower, and 37 feet for the AVEF I auxiliary boiler. The AVEF II cooling tower has a height of 48 feet, and the AVEF II auxiliary boiler has a stack height of 32 feet. All of the proposed stack heights are within GEP, and the proposed stack heights were used in the modeling analysis.

D. Dispersion Modeling Procedures

The ambient air quality impact analysis was conducted in accordance with an approved Air Quality Modeling Protocol. The protocol documents the model selection, GEP analysis methodology, and selection of the receptor network.

For AVEF I and for the near-field analysis of AVEF I and II in combination, initially the ISC3 model was used with regulatory default parameters set. Terrain in the vicinity of AVEF I and II is gently sloping with most of the elevations within 5-kilometers ranging between 800 and 950 feet msl. Two larger volcanic cinder cones to the northeast of the project site have elevations of 1088 and 1437 feet msl. Additional terrain features are located about 3 km northeast of the site and have elevations of 1072 and 1241 feet. The facility will be located at 881 feet MSL, and considering the stack heights at the facility, complex terrain modeling was required. Therefore, for short term CO concentration estimates and for combined PM_{10} impacts, a more refined model, CTSCREEN, was used to evaluate impacts on the complex terrain.

A single Cartesian receptor grid was initially generated that included receptors every 25 meters along the fenceline, 100-meter grid receptors from the fenceline out to 500 meters, a 250-meter grid out to 1 km, and a 500-meter grid out to 5 km. In addition to the initial Cartesian grid, impact grids of 100 meter spacing were placed at the location of maximum impacts, and at the two cinder cone peaks northeast of the site that became maximum impact points. Discrete receptors were also located at seven nearby Class II wilderness areas (Big Horn, Hummingbird Springs, Eagletail Mountain, Woolsey Peak, Sierra Estrella, North Maricopa Mountain, and Signal Hill), the Gila River Indian Community, and the Gila Bend Indian Reservation, all located within about 6 km of the facility.

The combined emissions of AVEF I and II were also modeled at distant Class I areas. The CALPUFF set of models and utilities were used for the distant (far-field) modeling. The five Class I areas examined were: the Superstition, Sierra Ancha, Pine Mountain, Mazatzal, and Sycamore Canyon Wilderness Areas. Regulatory default options were used in the models except for those parameters that had to be changed to reflect unique Arizona conditions.

E. Stack Emissions Characteristics Used in the Models

Ambient air quality impacts are a function of not only the magnitude of the emission rate (e.g., lb/hour) but also the emitting characteristics (e.g., exit temperature, exhaust flow rate, etc.) Merchant power plants tend to operate at variable load conditions and, therefore, variable emitting characteristics. Accordingly, Duke performed an analysis of the combination of emission rates and emitting characteristics that yielded the worst-case (highest) ambient air quality impacts. This analysis was conducted for each pollutant and standard averaging time (1-hour, 3-hour, 8-hour, 24-hour, and annual) and for each emitting source. The emissions modeled are representative of the BACT emission levels shown in Tables 4-1 through 4-17 (except for AVEF II NO_x which was analyzed at 2.5 ppm but was subsequently reduced to 2.0 ppm, and CO which was analyzed at 4.0 ppm and was reduced to 3.0 ppm), and included startup and shutdown emissions. Since the stack emissions characteristics do not change with the LAER-equivalent rates, if the locally enforceable limits were modeled, the ambient impacts would be less than shown in the following results.

F. Modeling Results

F.1 Combined AVEF I and II Initial Modeling Results

The results from modeling all 5 years of meteorological data indicate that the emissions from AVEF I combined with AVEF II exceeded the SILs for 24-hour and annual PM_{10} only. The maximum impact points were near the project site at locations from 3 to 6 km northeast to north-northwest of the plant site and are shown in Table 7-5.

Table 7-5
Maximum Ambient Air Quality Impacts
for Criteria Pollutants from AVEF I and AVEF II Combined

Pollutant	1-hour Average	3-hour Average	8-hour Average	24 hour Average	Annual Average
MAXIMUM IMPACTS OF AVEF I and AVEF II Combined					
SO_2		6.7 μg/m^3		1.4μg/m^3	0.2μg/m^3
PM_{10} (Note 3)				6.7μg/m^3 (Note 4)	1.1μg/m^3 (Note 4)
NO_2 (Note 1)					0.96μg/m^3
CO (Note 2)	1952 μg/m^3		481 μg/m^3 (Note 4)		
MAXIMUM IMPACTS COMPARED TO SILs					
SO_2		27%		28%	20%
PM_{10} (Note 3)				136%	110%
NO_2 (Note 1)					96%
CO (Note 2)	98%		96%		
MAXIMUM IMPACTS COMPARED TO CLASS II INCREMENTS					
SO_2		1%		2%	1%
PM_{10} (Note 3)				22%	6%
NO_2 (Note 1)					4%

Notes:

1. NO_x was converted to NO_2 based on an assumed conversion rate of 75%.
2. CO 8-hr concentration is based on all 8 hours of startup emissions from all four units, AVEF I and II.
3. PM_{10} emissions from the cooling tower based on 31.5% PM_{10} fraction.
4. These concentrations are the result of CTSCREEN modeling.

All maximum AVEF I and II combined impact concentrations are below the Class II increments and all are below the SILs except for the 24-hour and annual PM_{10} concentration.
The AVEF I and II combined impacts at the Class II areas and two Indian communities were much lower than the SILs, with the maximum impact occurring at the Signal Hill Wilderness Area located about 16 km south of the facility. The annual impacts for NO_x and PM_{10} were 0.13 and 0.18 ug/m^3, less than 18% of the SILs.

All impacts from AVEF I and II combined were below the pre-construction monitoring thresholds as well. However, since the AVEF I and II combined impacts exceeded the SILs for 24-hour and annual PM_{10}, refined modeling analysis, including an analysis of combined impacts of AVEF I and II with other nearby sources had to be conducted.

F.3 Cumulative AVEF I and II plus Other Nearby Sources Modeling Results

As stated, refined modeling for combined AVEF I and II had to be conducted only for 24-hour and annual PM_{10}. The maximum combined AVEF I and II 24-hour and annual PM_{10} impact occurred at a point 3.5 km northeast of the AVEF site, but the modeled concentrations (using the ISC3 model) exceeded the SILs out to a distance of 6.4 km. Therefore, the radius of the significant impact area (SIA) was established as 6.4 km. All "nearby" sources that could impact the SIA circle had to be modeled to evaluate cumulative impacts of AVEF I and II plus other nearby existing sources.

In order to conduct the cumulative modeling analysis, Duke obtained an emissions inventory from MCESD for all sources located within about 55 km of the AVEF site. A screening methodology was developed as part of the modeling protocol that demonstrated that only certain sources could contribute a significant cumulative impact. Only those sources with PM_{10} emissions less than 3 tons per year (tpy) within 15 km, 3 to 5 tpy within 20 km, 5 to 10 tpy within 30 km, 10 to 15 tpy within 40 km, and over 15 tpy within 55 km of the AVEF site were included in the cumulative impact model for evaluating increment consumption. The sources included in the cumulative increment consumption analysis were: Mesquite Generating Station, Pinnacle West Redhawk, Palo Verde Nuclear Generating Station, Harquahala Generating Company, Gila Bend, Acme Gin, Farmers Gin, Panda Gila River Project, Chickasha Cotton Oil, Allied Waste Industries, Anderson Clayton, and Arizona Grain.

The initial cumulative impact results of AVEF I, AVEF II and the other nearby sources (based on the ISC3 model) showed an apparent exceedance of the annual and 24-hour Class II increment at a high terrain peak located about 3.5 km northeast of the AVEF site. However, at this site, the contribution of AVEF I and II was very small (about 5%) compared to the Mesquite Generating Station contribution. Nevertheless, since there was an apparent exceedance, more refined modeling had to be conducted.

The refinement was to use the CTSCREEN model. The ISC3 model is essentially a flat terrain model that unrealistically treats high terrain by assuming that the height of the plume centerline is not affected by the underlying terrain. This unrealistic assumption can artificially double the concentration as the plume approaches high terrain points, in violation of the conservation of mass. The CTSCREEN model more realistically simulates the plume's interaction with terrain, allowing the plume to either travel around a hill or over a hill, depending upon atmospheric stability. Therefore, the complex terrain models do not violate conservation of mass and yield more representative, yet still conservative results.

One reason that CTSCREEN is conservative is that the model uses an assumed set of worst-case meteorology. Despite this conservatism, since the terrain treatment is more realistic, the CTSCREEN model indicated that the cumulative impacts of AVEF I, AVEF II, and the other nearby sources were less than the Class II increments. The maximum 24-hour PM_{10} cumulative impact using CTSCREEN was 23.2 ug/m^3, compared to the Class II increment of 30 ug/m^3.

CTSCREEN was also used to assess the cumulative impact on an annual average basis. It was found that the maximum annual PM_{10} impact was 4.6 ug/m^3, compared to the Class II increment of 17 ug/m^3.

F.4 Combined AVEF I and II Refined Modeling Results at Distant Class I Areas

The results of the CALPUFF modeling for the distant Class I areas are shown in Table 7-6. The results are compared to the Class I Significant Impact Levels (Class I SILs) developed by the Federal Land Managers. Note that the impacts are much less than the Class I SILs.

Table 7-6
Comparison of Maximum Modeled Refined CALPUFF Concentrations from AVEF I and II Combined to Proposed Class I Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)	Class I SIL (μg/m^3)	Location of Maximum Impact
NO_2	Annual	0.019	0.1	Superstition
PM_{10}	24-hour	0.28	0.3	Superstition
	Annual	0.039	0.2	Superstition
SO_2	3-hour	0.22	1.0	Pine Mountain
	24-hour	0.051	0.2	Superstition
	Annual	0.0071	0.1	Superstition

Since the Combined Impact of AVEF I and II is less than the Class I area SILS (as shown in Table 7-6), no cumulative impact is necessary.

VIII. AIR TOXICS IMPACT ANALYSIS

A. AVEF I Air Toxics Impact Analysis

The potential of AVEF I and II to cause exceedances of the Arizona Ambient Air Quality Guidelines (AAAQGs) was evaluated by determining AAAQG compound emissions and inputting the emission rates into the worst case ambient impact scenario. AAAQG compound emission rates were obtained from the USEPA emission factors in AP-42 and a site-specific emission factor for formaldehyde and hexane. The modeled impacts were compared to the most recent version (1999) of the annual and short term (1-hour and 24-hour) AAAQGs as published by ADEQ. The results are shown in Tables 8-1 through 8-3 and indicate maximum impacts much less than the relevant AAAQGs.

Table 8-1
Annual AAAQG Impact Results
AVEF I and II Combined

Compound	AVEF I Turbines (lb/hr)	AVEF I Duct Burner (lb/hr)	AVEF I Auxiliary Boiler (lb/hr)	AVEF II Turbines (lb/hr)	AVEF II Duct Burner (lb/hr)	AVEF II Auxiliary Boiler (lb/hr)	Annual Maximum Impact (μg/m3)	Arizona AAQG Annual (μg/m^3)
1,3-Butadiene	1.50E-03	---	---	1.01E-03	---	---	6.02E-05	3.60E-03
Acetaldehyde	1.39E-01	6.02E-03	1.81E-04	9.36E-02	7.62E-03	1.81E-04	6.31E-03	4.50E-01
Arsenic	---	1.42E-04	4.28E-06	---	1.80E-04	4.28E-06	1.69E-05	2.30E-04
Benzene	4.18E-02	1.49E-03	4.50E-05	2.81E-02	1.89E-03	4.50E-05	1.86E-03	1.20E-01
Benzo(a)anthracene	7.66E-03	1.28E-06	3.86E-08	5.15E-03	1.62E-06	3.86E-08	3.08E-04	4.80E-03
Benzo(a)pyrene	7.66E-03	8.52E-07	2.57E-08	5.15E-03	1.08E-06	2.57E-08	3.08E-04	4.80E-04
Beryllium	---	8.52E-06	2.57E-07	---	1.08E-05	2.57E-07	1.01E-06	4.20E-04
Cadmium	---	7.81E-04	2.36E-05	---	9.89E-04	2.36E-05	9.29E-05	5.60E-04
Dibenz(a,h)anthracene	7.66E-03	8.52E-07	2.57E-08	5.15E-03	1.08E-06	2.57E-08	3.08E-04	4.80E-04
Formaldehyde	1.27E+00	5.33E-02	1.61E-03	1.71E-01	6.75E-02	1.61E-03	4.00E-02	7.60E-02
Nickel	---	1.49E-03	4.50E-05	---	1.89E-03	4.50E-05	1.77E-04	2.10E-03
Propylene Oxide	1.01E-01	---	---	6.78E-02	---	---	4.06E-03	2.70E-01

Notes:

1) Facility total impact is assumed to be equal to the sum of individual source maximum impacts, regardless of location.
2) For those pollutants for which there is no emission factor, the source emission rate denoted by "---".
3) For individual turbine PAHs, it was assumed that each individual PAH comprised 100% of the composite PAH. Therefore, each individual turbine PAH emission rate reflects composite PAH. There is no AAAQG for composite PAH.

Table 8-2
24-Hour AAAQG Impact Results
AVEF I and II Combined

Compound	AVEF I Turbines (lb/hr)	AVEF I Duct Burner (lb/hr)	AVEF I Auxiliary Boiler (lb/hr)	AVEF II Turbines (lb/hr)	AVEF II Duct Burner (lb/hr)	AVEF II Auxiliary Boiler (lb/hr)	Annual Maximum Impact (μg/m3)	Arizona AAQG 24-Hour (μg/m^3)
1,3-Butadiene	1.50E-03	---	---	1.01E-03	---	---	4.21E-04	1.30E+00
Acetaldehyde	1.39E-01	6.02E-03	2.65E-04	9.36E-02	7.62E-03	2.65E-04	4.61E-02	1.70E+02

Acrolein	2.23E-02	---	---	1.50E-02	---	---	6.27E-03	2.00E+00
Ammonia	4.72E+01	---	---	4.72E+01	---	---	1.59E+01	1.40E+02
Arsenic	---	1.42E-04	6.25E-06	---	1.80E-04	6.25E-06	1.63E-04	1.60E-02
Barium	---	3.13E-03	1.38E-04	---	3.96E-03	1.38E-04	3.59E-03	4.00E+00
Benzaldehyde	---	1.12E-02	4.91E-04	---	1.41E-02	4.91E-04	1.28E-02	4.00E+01
Benzene	4.18E-02	1.49E-03	6.57E-05	2.81E-02	1.89E-03	6.57E-05	1.35E-02	4.40E+01
Benzo(a)anthracene	7.66E-03	1.28E-06	5.63E-08	5.15E-03	1.62E-06	5.63E-08	2.16E-03	1.60E+00
Benzo(a)pyrene	7.66E-03	8.52E-07	3.75E-08	5.15E-03	1.08E-06	3.75E-08	2.16E-03	1.80E-01
Beryllium	---	8.52E-06	3.75E-07	---	1.08E-05	3.75E-07	9.80E-06	1.60E-02
Cadmium	---	7.81E-04	3.44E-05	---	9.89E-04	3.44E-05	8.98E-04	2.00E-01
Chromium	---	9.95E-05	4.38E-06	---	1.26E-04	4.38E-06	1.14E-04	4.00E+00
Copper	---	6.04E-04	2.66E-05	---	7.65E-04	2.66E-05	6.94E-04	7.90E-01
Dibenz(a,h)anthracene	7.66E-03	8.52E-07	3.75E-08	5.15E-03	1.08E-06	3.75E-08	2.16E-03	1.80E-01
Ethylbenzene	1.11E-01	---	---	7.49E-02	---	---	3.14E-02	3.50E+03
Formaldehyde	1.27E+00	5.33E-02	2.35E-03	1.71E-01	6.75E-02	2.35E-03	3.03E-01	1.60E+01
Hexane	7.59E-01	5.08E-02	2.24E-03	5.10E-01	6.44E-02	2.24E-03	2.72E-01	1.40E+03
Lead	---	3.55E-04	1.56E-05	---	4.50E-04	1.56E-05	4.08E-04	1.50E+00
Manganese	---	2.70E-04	1.19E-05	---	3.42E-04	1.19E-05	3.10E-04	7.90E+00
Mercury	---	1.85E-04	8.13E-06	---	2.34E-04	8.13E-06	2.12E-04	4.00E-01
Napthalene	4.53E-03	4.33E-04	1.91E-05	3.04E-03	5.49E-04	1.91E-05	1.77E-03	4.00E+02
Nickel	---	1.49E-03	6.57E-05	---	1.89E-03	6.57E-05	1.72E-03	1.20E-01
Pentane	---	1.85E+00	8.13E-02	---	2.34E+00	8.13E-02	2.12E+00	1.40E+04
Propane	---	1.14E+00	5.00E-02	---	1.44E+00	5.00E-02	1.31E+00	1.40E+04
Propylene Oxide	1.01E-01	---	---	6.78E-02	---	---	2.84E-02	9.80E+01
Selenium	---	1.70E-05	7.51E-07	---	2.16E-05	7.51E-07	1.96E-05	1.60E+00
Toluene	4.53E-01	2.42E-03	1.06E-04	3.04E-01	3.06E-03	1.06E-04	1.30E-01	3.00E+03
Vanadium	---	1.63E-03	7.19E-05	---	2.07E-03	7.19E-05	1.88E-03	4.00E-01
Xylene (total)	2.23E-01	---	---	1.50E-01	---	---	6.27E-02	3.50E+03

Notes:

1) Facility total impact is assumed to be equal to the sum of individual source maximum impacts, regardless of location.
2) For those pollutants for which there is no emission factor, the source emission rate denoted by "---".
3) For individual turbine PAHs, it was assumed that each individual PAH comprised 100% of the composite PAH. Therefore, each individual turbine PAH emission rate reflects composite PAH. There is no AAAQG for composite PAH.

Table 8-3
1-Hour AAAQG Impact Results
AVEF I and II Combined

Compound	AVEF I Turbines (lb/hr)	AVEF I Duct Burner (lb/hr)	AVEF I Auxiliary Boiler (lb/hr)	AVEF II Turbines (lb/hr)	AVEF II Duct Burner (lb/hr)	AVEF II Auxiliary Boiler (lb/hr)	Annual Maximum Impact (μg/m3)	Arizona AAQG 1-Hour (μg/m^3)
1,3-Butadiene	1.50E-03	---	---	1.01E-03	---	---	3.81E-03	5.00E+00
Acetaldehyde	1.39E-01	6.02E-03	2.65E-04	9.36E-02	7.62E-03	2.65E-04	3.99E-01	6.30E+02
Acrolein	2.23E-02	---	---	1.50E-02	---	---	5.67E-02	6.30E+00
Ammonia	4.72E+01	---	---	4.72E+01	---	---	1.43E+02	2.30E+02
Arsenic	---	1.42E-04	6.25E-06	---	1.80E-04	6.25E-06	1.04E-03	6.00E-02

Barium	---	3.13E-03	1.38E-04	---	3.96E-03	1.38E-04	2.30E-02	1.50E+01
Benzaldehyde	---	1.12E-02	4.91E-04	---	1.41E-02	4.91E-04	8.20E-02	8.30E+01
Benzene	4.18E-02	1.49E-03	6.57E-05	2.81E-02	1.89E-03	6.57E-05	1.17E-01	1.70E+02
Benzo(a)anthracene	7.66E-03	1.28E-06	5.63E-08	5.15E-03	1.62E-06	5.63E-08	1.95E-02	6.00E+00
Benzo(a)pyrene	7.66E-03	8.52E-07	3.75E-08	5.15E-03	1.08E-06	3.75E-08	1.95E-02	6.70E-01
Beryllium	---	8.52E-06	3.75E-07	---	1.08E-05	3.75E-07	6.26E-05	6.00E-02
Cadmium	---	7.81E-04	3.44E-05	---	9.89E-04	3.44E-05	5.74E-03	7.70E-01
Chromium	---	9.95E-05	4.38E-06	---	1.26E-04	4.38E-06	7.31E-04	1.50E+01
Copper	---	6.04E-04	2.66E-05	---	7.65E-04	2.66E-05	4.44E-03	3.00E+00
Dibenz(a,h)anthracene	7.66E-03	8.52E-07	3.75E-08	5.15E-03	1.08E-06	3.75E-08	1.95E-02	6.70E-01
Ethylbenzene	1.11E-01	---	---	7.49E-02	---	---	2.84E-01	4.50E+03
Formaldehyde	1.27E+00	5.33E-02	2.35E-03	1.71E-01	6.75E-02	2.35E-03	2.60E+00	2.50E+01
Hexane	7.59E-01	5.08E-02	2.24E-03	5.10E-01	6.44E-02	2.24E-03	2.31E+00	5.40E+03
Lead	---	3.55E-04	1.56E-05	---	4.50E-04	1.56E-05	2.61E-03	NAAQS
Manganese	---	2.70E-04	1.19E-05	---	3.42E-04	1.19E-05	1.98E-03	2.50E+01
Mercury	---	1.85E-04	8.13E-06	---	2.34E-04	8.13E-06	1.36E-03	1.50E+00
Napthalene	4.53E-03	4.33E-04	1.91E-05	3.04E-03	5.49E-04	1.91E-05	1.47E-02	6.30E+02
Nickel	---	1.49E-03	6.57E-05	---	1.89E-03	6.57E-05	1.10E-02	4.50E-01
Pentane	---	1.85E+00	8.13E-02	---	2.34E+00	8.13E-02	1.36E+01	1.90E+04
Propane	---	1.14E+00	5.00E-02	---	1.44E+00	5.00E-02	8.35E+00	5.40E+04
Propylene Oxide	1.01E-01	---	---	6.78E-02	---	---	2.57E-01	3.70E+02
Selenium	---	1.70E-05	7.51E-07	---	2.16E-05	7.51E-07	1.25E-04	6.00E+00
Toluene	4.53E-01	2.42E-03	1.06E-04	3.04E-01	3.06E-03	1.06E-04	1.17E+00	4.40E+03
Vanadium	---	1.63E-03	7.19E-05	---	2.07E-03	7.19E-05	1.20E-02	1.50E+00
Xylene (total)	2.23E-01	---	---	1.50E-01	---	---	5.67E-01	5.40E+03

Notes:

1) Facility total impact is assumed to be equal to the sum of individual source maximum impacts, regardless of location.
2) For those pollutants for which there is no emission factor, the source emission rate denoted by "---".
3) For individual turbine PAHs, it was assumed that each individual PAH comprised 100% of the composite PAH. Therefore, each individual turbine PAH emission rate reflects composite PAH. There is no AAAQG for composite PAH.

IX. URBAN AIRSHED MODELING

MCESD Rule 240.308.1(e)(2) states that any major source of NO_x or VOCs located within 50 km of the nonattainment area boundary shall be presumed to contribute to violations of the ozone standard in the nonattainment area unless it can be shown because of physical terrain, meteorology, or other physical factors the source is not expected to contribute to violations.

Duke analyzed the potential of AVEF I to contribute to ozone violations in the nonattainment area by (among other analyses) conducting Urban Airshed Modeling (UAM) that included the combined impact of the proposed Pinnacle West Redhawk generating station and the proposed AVEF I.

The model results were that Redhawk and AVEF I combined cause an apparent extremely small increase of 0.0146 ppb in the peak ozone concentration in the nonattainment area (worst case day and location). This "increase" is within the numerical noise of the UAM model. Maximum increases of 4.005 ppb with Redhawk alone and 4.427 ppb with Redhawk and AVEF I combined were found, but these increases were in the low ozone concentration areas on the western edge of the nonattainment boundary. On days and locations where the ozone concentration is predicted to be greater than 124 ppb without either Redhawk or AVEF I, adding the two generating station emissions cause ozone increases of less than 0.098 ppb.

The analysis showed that Redhawk and AVEF I combined would not cause any new exceedances of the ozone 1-hour standard or exacerbations of existing exceedances of this standard.

Duke also analyzed the combined impact of AVEF I and AVEF II with other nearby major sources permitted since the AVEF I analysis was completed. The nearby major sources included Redhawk, Mesquite, AVEF I, Gila River, and Gila Bend. Duke analyzed three scenarios:

- The 1999 existing baseline prior to any Arlington Valley nearby power plant permits ("Baseline"),
- The 1999 baseline plus the five previously permitted plants ("Five-Plant Baseline"), and
- The 1999 baseline plus the five previously permitted plants plus the proposed AVEF II facility ("Cumulative").

The results are shown in Tables 9-1 and 9-2 for the worst-case ozone design day of July 23. As these tables show, the proposed AVEF II appears to add an extremely small increase in ozone concentration (0.078 ppb). However, this apparent increase is within the numerical uncertainty of the UAM-IV model. Therefore it is concluded that the cumulative emissions of the five plants plus AVEF II will not contribute to or cause an exceedance of the ozone standard in the Maricopa County nonattainment area.

Table 9-1
Daily Maximum UAM-IV Ozone Predictions (ppm) for 1999 Baseline and Project Impact Scenarios for July 23

Incremental Scenario	Maximum Hourly O3 (ppb)
Baseline Scenario	165
Five Plant Scenario	165
Cumulative Scenario Including AVEF II	165

Note: AVEF II analyzed at 2.5 ppm NO_x

Table 9-2
Incremental UAM-IV Ozone Predictions (ppm) for 1999 Baseline and Project Impact Scenarios for July 23

Incremental Scenario	O_3 Difference (ppb)
Change between Baseline and Five Project Baseline in the Maximum Daily Predicted Ozone	0.594
Change between Baseline and Cumulative in the Maximum Daily Predicted Ozone	0.669
Change between Five Plant Baseline and Cumulative in the Maximum Daily Predicted Ozone	0.078

Note: AVEF II analyzed at 2.5 ppm NO_x

X. ADDITIONAL IMPACT ANALYSIS

A. Visibility Impacts in Nearby Class II Areas

The PSD regulations require that PSD permit applications address the potential impairment to visibility in Class I areas. Class I areas are national or regional areas of special natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. The nearest Class I area to AVEF I and II is the Superstition Wilderness Area about 120 km (75 miles) east of the site. The Superstition Wilderness Area is so distant that visibility impacts from AVEF I are not likely. Therefore, when AVEF I was permitted, no visibility analysis was conducted for the Superstition Wilderness for AVEF I alone. However, as part of the AVEF II analysis, a visibility impact analysis at the Superstition Wilderness was conducted for both AVEF I and II. The results of this analysis are discussed in the following paragraphs.

There are an additional seven Class II Wilderness areas within about 50 km of the site: Hummingbird Springs, Big Horn, Eagletail Mountain, Signal Hill, Woolsey Peak, North Maricopa Mountain, and Sierra Estrella. There are also two Indian Reservations within about 50 km of the site: Gila Bend and Gila River. Although not required by PSD regulations, Duke analyzed the potential visibility impact on the seven nearby Class II areas and two Indian Communities for AVEF I alone and for the combined impact of AVEF I plus II. For AVEF I alone Duke used a Level II analysis with the VISCREEN plume visibility model. VISCREEN is known to yield highly conservative results (i.e., over-predict impacts). In addition, Duke used the maximum permitted particulate and NO_x emission rates, including the very large condensable component assumed by Duke and its vendor. Finally, Duke compared the VISCREEN results to Class I area criteria, even though Class II criteria, if there were any, would probably be significantly less stringent than the Class I criteria. For AVEF I, alone this combination of conservatism resulted in plume contrast values during worst case conditions (worst case meteorology coupled with worst case AVEF I emissions) about double the Class I criteria and about six times the Class I coloration criteria (delta E) for adverse visibility impacts. These results are mainly the result of the relatively high assumed condensable particulate emissions. When the plume is modeled with only NO_x emissions, the VISCREEN results are about one-tenth the Class I contrast criteria and less than one-half the coloration criteria. This result is what would be expected from a natural gas fired power plant, and actual visibility impacts are not anticipated.

Duke also used the Level II VISCREEN analysis to initially evaluate the visibility impacts of AVEF I and II combined. This conservative analysis again showed maximum plume contract values during worst case conditions about five times the Class I plume contrast criterion and 6.5 times the coloration criterion. Therefore, for the two Class II areas (Signal Hill and Woolsey Peak) and the Indian Reservation (Gila River) that had the highest visibility impact results, a more refined analysis using the PLUVUE II model was conducted.

PLUVUE II models visibility impacts for specific lines of sight and sun-plume-observer-geometry for specific meteorological conditions. Duke's analysis showed that maximum visible impacts occur during wintertime mornings. Two different background visual ranges were used for the analysis: a 177 km background visual range representing the best 20% of existing visibility conditions, and 224 km representing the 90-percentile of visibility conditions. The results are shown in Tables 10-1 and 10-2.

Table 10-1
PLUVUE II Level 2 Wintertime Results for Class II Areas
for a Background Visual Range of 177 km

Class II Area	Month	Plume Perceptibility ΔE (L*A*B)	Plume Contrast (at 0.55 μm)

Class II Area	Month	Plume Perceptibility ΔE (L*A*B)	Plume Contrast (at 0.55 μm)
Woolsey Peak Wilderness	Jan	0.53	-0.011
	Feb	0.82	-0.019
	Nov	0.47	-0.007
	Dec	1.02	-0.02
Signal Mountain Wilderness	Jan	1.60	0.026
	Feb	2.82	0.017
	Nov	0.54	0.001
	Dec	0.50	-0.002
Gila River Indian Reservation	Jan	3.23	0.057
	Feb	0.38	-0.09
	Nov	0.43	-0.009
	Dec	0.34	-0.007

Notes:
1. Although for computational reasons a large number range of lines-of-sight were included in the PLUVUE analyses, these results are specific to lines-of-sight that pass directly across the plume at the distance that the plume passes the respective Class II area. Consideration of lines-of-sight either up up-plume or down-plume would constitute an integral vista, which is not subject to visibility regulations.
2. Class I Significance Criteria are 2.0 for ΔE and 0.05 for contrast
3. AVEF II analyzed at 2.5 ppm NO_x

Table 10-2
PLUVUE II Level 2 Wintertime Results for Class II Areas
for a Background Visual Range of 244 km

Class II Area	Month	Plume Perceptibility ΔE (L*A*B)	Plume Contrast (at 0.55 μm)
Woolsey Peak Wilderness	Jan	0.57	-0.012
	Feb	0.90	-0.022
	Nov	0.48	-0.008
	Dec	1.08	-0.023
Signal Mountain Wilderness	Jan	1.90	0.035
	Feb	3.3	0.02
	Nov	0.60	0.003
	Dec	0.57	-0.001
Gila River Indian Reservation	Jan	4.16	0.083
	Feb	0.43	-0.011
	Nov	0.46	-0.010
	Dec	0.37	-0.009

Notes:
1. Although for computational reasons a large number range of lines-of-sight were included in the PLUVUE analyses, these results are specific to lines-of-sight that pass directly across the plume at the distance that the plume passes the respective Class II area. Consideration of lines-of-sight either up up-plume or down-plume would constitute an integral vista, which is not subject to visibility

Class II Area	Month	Plume Perceptibility ΔE (L*A*B)	Plume Contrast (at 0.55 μm)
regulations. 2. Class I Significance Criteria are 2.0 for ΔE and 0.05 for contrast 3. AVEF II analyzed at 2.5 ppm NO_x			

The modeling results overstate the potential visual impact of the proposed facility for four primary reasons. First, the formulation of the PLUVUE II model is conservative and is designed to yield high estimates of potential impacts. Second, the PM_{10} emission rates are based upon conservative vendor guarantees rather than actual source test data. Since vendor guarantees are, by definition, conservative estimates of emissions and include the probable significant over-estimate of the condensable particulate emissions from the combustion turbines, the actual expected PM_{10} emission rates will likely be much lower than modeled for the analysis. Third, the analysis assumes persistence of worst-case meteorological conditions that typically occur for only a few hours near sunrise or sunset. The transport times for the wind speeds modeled (1 – 2 meters per second) requires persistence of these conditions for two or more hours for the plume to reach the Wilderness Areas. In complex terrain such as exists near the AVEF facility, the persistence of a given set of low wind speed meteorological conditions beyond a few hours is suspect. If the plume is in direct sunlight (as modeled with VISCREEN and PLUVUE II) and the winds are light (as determined by the Level II meteorological frequency analysis) the atmosphere will rapidly become unstable after sunrise and the visible plume will dissipate rapidly.

Finally, the Gila River Indian Reservation is south of the Woolsey Peak Wilderness Area. Terrain differences in excess of 2,500 feet exist between the AVEF II facility and the Gila River Class II area. It is highly unlikely that a plume could traverse the rugged terrain in the Woolsey Peak Wilderness Area and maintain its coherence. Consequently, the modeling results for the Gila River area are of questionable validity.

Based on the above refined PLUVUE II analysis, the potential for visual impact by a coherent plume exists for only a limited number of hours per year. For both the 177 km and the 224 km background condition, at Signal Mountain, the coloration criterion exceeds the Class I screening value for only one month. No criteria are exceeded at Woolsey Peak, while the modeling results for Gila River are of questionable validity. However, it is extremely unlikely that the worst-case meteorological conditions modeled in the PLUVUE model and the 80^{th} or 90^{th}-percentile background visual range represented by the 177 km or 224 km background visual range occurs at the same time. Therefore, the combined impact of the AVEF I and II facility is not expected to have a significant visual impact on the nearby Class II areas evaluated.

B. Visibility Impacts in Distant Class I Areas (Regional Haze)

The CALPUFF and CALPOST set of models was used to evaluate the combined visibility impact of AVEF I and II on the five distant Class I areas (Superstition, Sierra Ancha, Pine Mountain, Mazatzal, and Sycamore Canyon). At distant locations, the visibility impact is related to regional haze and the Class I significance criterion is a change in extinction of 5%. The results of the regional haze analysis are shown in Table 10-3. The Table shows that the 5% change in extinction significance criterion was not exceeded at any of the areas.

Table 10-3
Maximum 24-Hour Average Regional Haze Impacts on the Class I Areas

Class I Area	Parameter	1986	1987	1988	1989	1990	Maximum
Superstition	Largest Extinction Change (%)	3.2	4.1	3.7	3.0	4.6	4.6

Table 10-3
Maximum 24-Hour Average Regional Haze Impacts on the Class I Areas

Class I Area	Parameter	1986	1987	1988	1989	1990	Maximum
	# Days with =>5% Extinction Change	0	0	0	0	0	0
Sierra Ancha	Largest Extinction Change %	2.5	2.2	2.3	2.0	2.6	2.6
	# Days with =>5% Extinction Change	0	0	0	0	0	0
Pine Mountain	Largest Extinction Change %	3.1	3.3	4.2	2.7	4.8	4.8
	# Days with =>5% Extinction Change	0	0	0	0	0	0
Mazatzal	Largest Extinction Change %	3.1	3.5	4.0	2.7	4.7	4.7
	# Days with =>5% Extinction Change	0	0	0	0	0	0
Sycamore Canyon	Largest Extinction Change %	2.6	2.2	2.4	2.1	2.7	2.7
	# Days with =>5% Extinction Change	0	0	0	0	0	0

Notes: All extinction values are rounded to two significant figures
AVEF II analyzed at 2.5 ppm NO_x

C. Acid Deposition

Although not required by PSD regulations, Duke analyzed the potential for acid deposition (both dry and wet) at the nearest Class II area (Signal Hill Wilderness Area) by using the ISC model concentrations and an assumed deposition velocity. A maximum deposition of less than 1.2 kilograms per hectare per year (kg/ha-yr) nitrogen was estimated for AVEF I and a maximum of less than 2.5 kg/ha-yr nitrogen from AVEF I and II combined. There are no criterion for acceptable acid deposition values, but the combined impact of AVEF I and II is not anticipated to significantly contribute to acid deposition.

Acid deposition was also evaluated at the Class I areas by using the CALPUFF model along with the CALPOST program. Maximum deposition occurred at the Superstition Wilderness Area, and was 0.0034 kg/ha-yr nitrogen and 0.0017 kg/ha-yr sulfur. These values are less than one-tenth the US Forest Service criterion for Class I areas of 0.05 kg/ha-yr.

D. Growth Analysis

AVEF I and II will each employ approximately 300 personnel during the construction phase (however the construction phases will not necessarily occur at the same time) and AVEF I will employ approximate 25 personnel on a permanent basis. AVEF II will employ approximately an additional 8 personnel on a permanent basis. AVEF I and II both hope to hire from the local communities where possible, and there should be no substantial increase in community growth or need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary emissions associated with growth.

E. Soils and Vegetation Analysis

USEPA Guidelines published in "A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA_450/2-81-078) states that an analysis of a source's impacts on soils and vegetation is not required when the source is more than 10 km from a Class I area and impacts are modeled to be below the SILs. Although the combined impact of AVEF I and II exceeded the 24-hour SIL for PM_{10}, it did not exceed the annual SIL. Therefore, AVEF I and II are not anticipated to have an adverse impact on soils and vegetation.

XI. ENDANGERED SPECIES ACT

Duke has consulted with US Fish and Wildlife Service (USFWS), the Arizona Department of Game and Fish (ADGF), and the Arizona Department of Agriculture (ADA) to determine if endangered species could be adversely affected by AVEF I and II. In addition, Duke conducted literature reviews, database searches, and field evaluations. The results of these reviews indicated that the construction and operation of AVEF I and II are not expected to impact threatened, endangered, or special status plans and animals identified by the USFWS, AGFD, and ADA.

XII. REGULATORY STREAMLINING

A. Applicable Requirements

The proposed project is subject to a number of applicable New Source Performance Standards (NSPS) that contain requirements much less stringent than the requirements established in the proposed permit for AVEF I. The permit conditions are drafted to incorporate the most stringent requirements. The main requirements that have been streamlined are as follows:

1. 40 CFR 60 Subpart Da Requirement NO_x Limit for the Duct Burners

There are three emission limits in Subpart Da that affect the duct burners (only) at AVEF I and II: a particulate limit of 0.03 lb/mmBtu (40 CFR 60.42a(1)), an SO_2 limit of 0.20 lb/mmBtu (40 CFR 60.43a(b)(2)), and a NO_x limit of 1.6 pound per megawatt hour gross energy output on a 30-day rolling average (40 CFR 60.44a(d)(1)). The particulate matter limit is explicitly included in the permit.

AVEF I duct burner NO_x and SO_2 limits are *implicitly* included in the permit by the sulphur content in natural gas requirement (0.75 grains per 100 dscf) and the NO_x limit of 3 ppm on a 3-hour rolling average. The calculations demonstrating the streamlining are as follows:

$$Duct\ Burner\ NO_x\ Emissions\ (lb\ NO_x / MW - hr) = \left(\frac{Duct\ Burner\ NO_x\ emissions\ (lb/hr)}{Duct\ Burner\ Steam\ Turbine\ Output\ (MW)} \right)$$

- Duct burner NO_x emissions are calculated by taking the difference between NO_x emissions with and without the duct burner operating.
- Duct burner Steam Turbine Output is calculated by taking the difference in the Steam Turbine output with and without the duct burner operating.

For an ambient temperature of 66.3 degrees F and full load, the duct burner NO_x emissions are 3.95 pounds per hour per unit and the electrical generation rate per unit under these conditions is 41.7 megawatts. Therefore, the duct burner emissions in terms of lb NO_x per MWe-hr are 0.095 lb/MWe-hr (3.95/41.7 = 0.095). This is less than 6% of the 1.6 lb/MWe-hr Subpart Da limit.

$$Duct\ Burner\ SO_2\ Emissions\ (lb\ SO_2/MMBtu(LHV)) = \left(\frac{Duct\ Burner\ SO_2\ emissions\ (lb/hr)}{Duct\ Burner\ Fuel\ Input\ (MMBtu/hr\ (LHV))}\right)$$

- Duct Burner SO_2 emissions are calculated by taking the difference between SO_2 emissions with and without the duct burner operating.

For an ambient temperature of 66.3 degrees F and full load, the duct burner SO_2 emissions are 0.75 lb/hour and the lower heating value heat rate input is 321.5 mmBtu. Therefore, the SO_2 emissions are 0.0023 lb/mmBtu (LHV). This is less than 2% of the 0.20 lb/mmBtu limit.

AVEF II duct burner NO_x and SO_2 limits are also *implicitly* included in the permit by the sulphur content in natural gas requirement (0.75 grains per 100 dscf) and the NO_x limit of 2.5 ppmvd on a 3-hour rolling average. The calculations demonstrating the streamlining are as follows:

$$Duct\ Burner\ NO_x\ Emissions\ (lb\ NO_x/MW-hr) = \left(\frac{Duct\ Burner\ NO_x\ emissions\ (lb/hr)}{Duct\ Burner\ Steam\ Turbine\ Output\ (MW)}\right)$$

- Duct burner NO_x emissions are calculated by taking the difference between NO_x emissions with and without the duct burner operating.
- Duct burner Steam Turbine Output is calculated by taking the difference in the Steam Turbine output with and without the duct burner operating.

For an ambient temperature of 66.3 degrees F and full load, the duct burner NO_x emissions at the BACT level are 6.1 pounds per hour per unit and the electrical generation rate per unit under these conditions is 75.7 megawatts. Therefore, the duct burner emissions in terms of lb NO_x per MWe-hr are 0.08 lb/MWe-hr (6.1/75.7 = 0.08). This is less than 5% of the 1.6 lb/MWe-hr Subpart Da limit.

$$Duct\ Burner\ SO_2\ Emissions\ (lb\ SO_2/MMBtu(LHV)) = \left(\frac{Duct\ Burner\ SO_2\ emissions\ (lb/hr)}{Duct\ Burner\ Fuel\ Input\ (MMBtu/hr\ (LHV))}\right)$$

- Duct Burner SO_2 emissions are calculated by taking the difference between SO_2 emissions with and without the duct burner operating.

For an ambient temperature of 66.3 degrees F and full load, the duct burner SO_2 emissions are 1.40 lb/hour and the lower heating value heat rate input is 603.7 mmBtu/hr per unit. Therefore, the SO_2 emissions are 0.0023 lb/mmBtu (LHV). This is less than 2% of the 0.20 lb/mmBtu limit.

When AVEF I was originally permitted, 40 CFR Subpart Da also required exhaust flow monitoring, and those requirements were included in the Permit. However, AVEF I requested a waiver from the USEPA and MCESD to substitute use of a continuous fuel flow monitoring system to monitor fuel input rate and measured Gross Calorific Value (GCV) of the natural gas burned, together with the 40 CFR Part 75 continuous emission monitoring (CEM) systems for NO_x to demonstrate compliance with 40 CFR Subpart Da. This waiver was granted.

On April 10, 2001, the USEPA published a direct final rule (which was slightly revised on June 11, 2001) that specifically addressed duct burners in combined cycle systems that are subject to Subpart Da requirements. The April 10, 2001 revisions explicitly allow GCV fuel monitoring instead of exhaust flow rate monitoring. This revision is incorporated into the permit for both AVEF I and II. In addition, the April 10, 2001 revisions explicitly allow CEM data to be used for NO_x compliance. If CEM data are used, the Subpart Da limit of 1.6 lb NO_x per MWe is applied to the entire output of the combustion turbine system (combustion turbines plus duct burners). That revision is also included in the permit for AVEF I and II.

Permit Condition 21.B. of the proposed permit contains the record keeping and reporting requirements of 40 CFR Part 60. However, that permit condition also contains some record keeping and reporting required by the County for CO continuous emission monitors as well as requirements beyond those required by Part 60 for NO_x monitors. The difference is noted by citing either Part 60 alone (for the Part 60 requirements) or both Part 60 and County Rule 210 for those requirements that are necessary to meet both the Part 60 and local County requirements.

2. 40 CFR Subpart GG NO_x Emission Limit

40 CFR 60.332(a)(1) limits emissions of NO_x from the combustion turbine to 0.01% by volume, corrected to 15% oxygen. This is equivalent to 100 parts per million by volume (100 parts per 1,000,000 parts x 100 = 0.01%). At AVEF I, the NO_x emissions are limited to 3 ppm by volume corrected to 15% oxygen and at AVEF II the NO_x emissions are limited to 2.5 ppm. Clearly, the AVEF I and II permit limits are more stringent than the Subpart GG limits.

3. Maricopa County Rule 241 – County Control Technology Requirements

Rule 241 establishes control technology requirements for sources not subject to Rule 240, Federal major source New Source Review (NSR) permitting. For the proposed project, the only pollutant that meets this criterion is SO_2. Rule 241 contains emission thresholds for applicability, which for SO_2 is 150 lb/day or 25 TPY. Rule 241 affected requires sources to install BACT.

Emissions of SO_2 from AVEF I and II exceed the Rule 241 threshold for SO_2. However, AVEF I and II has demonstrated BACT for SO_2 through the use of low sulfur diesel fuel (for the emergency generators) and pipeline quality natural gas as the only fuels that will be used.

B. Non-Applicable Requirements

The proposed permit contains a section indicating that certain regulations are not applicable to AVEF I and II. There are, obviously, a very large set of regulations that do not apply to AVEF I and II, but the permit calls out a few specifically in order to avoid future confusion. The rationale for the conclusion that the noted regulations are not applicable is as follows:

1. CAA Section 112(g), *Case by Case MACT* and 40 CFR Part 63, *NESHAPs for Major Sources of HAPs*

   AVEF I and II is not a major Federal HAPs source, with total HAPs emissions of 22.5 tons per year and no one HAP greater than 9 tons per year for combined emissions from AVEF I and II

2. 40 CFR 60 Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*

   Subpart D applies to steam generating units over 250 mmBtu/hr that are not electric generating units. AVEF I and II are electric generating stations, so Subpart D does not apply.

3. 40 CFR 60 Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

   Subpart Db applies to steam generating units over 100 mmBtu/hr that are not subject to Subpart Da. The duct burners are the only "steam generating units" rated at over 100 mmBtu/hr, but the duct burners are rated at over 250 mmBtu/hr and are subject to Subpart Da. Units subject to Subpart Da are not subject to Db.

4. 40 CFR 64, *Compliance Assurance Monitoring (CAM)*

   The CAM rule applies only to emission units with pre-control emissions greater than major source thresholds (100 tons per year in the case of AVEF I), that are not regulated by NSPS or NESHAPs issued after November 15, 1990, not regulated by the Acid Rain Program, not subject to a Title V continuous compliance determination method (e.g., CEMs), among other exemptions; and that use an active control device to reduce emissions.

   The only emission units at AVEF I with pre-control emissions over 100 tons per year are the Combined Cycle Systems NO_x, CO and PM_{10} and the cooling towers PM_{10}. NO_x from the combustion turbines is controlled by SCR. However, the combustion turbines NO_x emissions are under the Acid Rain Program and are subject to a continuance compliance demonstration in the Title V permit. The remaining pollutants from the Combustion Turbine and the cooling towers are not controlled by an active control device as defined by 40 CFR 64.1. Therefore, CAM does not apply to AVEF I.

   The only emission units at AVEF II with pre-control emissions over 100 tons per year are the Combined Cycle Systems NO_x, CO and PM_{10} and the cooling towers PM_{10}. NO_x from the combustion turbines is controlled by SCR. However, the combustion turbines NO_x emissions are under the Acid Rain Program and are subject to a continuous compliance demonstration in the Title V permit. CO from the Combined Cycle Systems is controlled by a CAT-OX. However, the CO emissions are subject to a continuous compliance demonstration in the Title V permit. The remaining pollutants from the Combustion Turbine and the cooling towers are not controlled by an active control device as defined by 40 CFR 64.1. Therefore, CAM does not apply to AVEF II.

5. 40 CFR 75.17, *Affected Units Exhausting through a Common Stack*

   AVEF I and II use four separate stacks for the four Combined Cycle Systems, so this provision does not apply.

6. Maricopa County Rule 245 – *Continuous Monitoring Requirements*

   Continuous monitoring requirements for various sources, including fossil fuel-fired steam generators, are contained in Rule 245. However, per Section 306.1 of Rule 245, sources subject to a Federal New Source Performance Standard (NSPS) are exempt from the requirements in Rule 245. The Combustion Turbines, Auxiliary Boiler, and Duct Burners are all subject to NSPS. Thus, the monitoring requirements of Rule 245 are not applicable and are effectively subsumed by the NSPS requirements.

7. Maricopa County Rule 370 – *Hazardous Air Pollutants (HAPs)*

   The Federal HAPs program is only applicable to major sources of HAPs. AVEF I and II is not a major source of HAPs, so these regulations do not apply.

   The State of Arizona has also adopted a State HAPs program under A.R.S. Section 429.06. The applicability thresholds for the State HAPs program are 2.5 TPY or more of any combination of HAPs or 1.0 TPY or more of a single HAP. The State HAPs program will only be effective once the Arizona DEQ adopts implementing regulations; under A.R.S. Section 49-480.04 Maricopa County will be required to implement the State HAPs program in Maricopa County at that time. Hence, currently there is no applicable State HAPs program. Moreover, the exemption for electric utility steam generating units also applies to the State HAPs program.

In absence of the State HAPs program, Maricopa County requests that facilities model HAP emissions to show compliance with a set of Arizona Ambient Air Quality Guidelines (AAAQG). Modeling was submitted for the AVEF I and II facility. As discussed in Section VIII, the results demonstrate that the potential project HAP emissions do not exceed the AAAQG.

C. Other Applicable Requirements

1. Maricopa County Rule 270 – *Performance Testing*

   Rule 270 contains performance and compliance testing requirements and establishes requirements for testing criteria, conditions, and reporting of test results. The Rule 270 performance testing requirements are specified in the permit.

2. Maricopa County Rule 300 – *Opacity Regulations*

   Requirements for visible emissions are established in Rule 300. Opacity is to be 20% or less with a few exceptions (start-up, shutdown, or unavoidable combustion irregularities not exceeding three minutes as in Section 302.1). Opacity requirements are contained in the permit, and EPA Reference Method 9 is to be used to determine opacity when required. The proposed combined cycle units will only combust natural gas, which is a clean burning fuel, and such equipment rarely, if ever, exceeds 20% opacity. As a result, no continuous monitoring for opacity is required.

3. Maricopa County Rule 304 and 311, State Rule R18-2-719.c.1, and SIP Rule 31(H) – *Particulate Matter*

   Rule 311 contains PM emission limits for process industries, and since AVEF I and II is not a "process industry", the rule is not applicable. However, SIP Rule 31(H) includes limitations for fuel burning operations that are applicable. An equation to calculate maximum allowable PM emissions is provided in Section 304.1 for equipment with a heat input rating of 4200 mmBtu/hr or less. The BACT PM emission limits from the combined cycle units will be much less than this limit, and therefore it is effectively subsumed.

   State Rule R18-2-719.c.1 applies to diesel-fired fuel burning equipment that is not subject to NSPS. Therefore, the requirements of this rule are applicable only to the emergency fire water pump engine and the back-up generator. The emission limits are based on the same equation as for SIP Rule 31(H).

4. Maricopa County Rule 320 – *Odors and Gaseous Air Contaminants*

   Sections 306 and 308 of Rule 320 contain SO_2 and NO_x limitations for electrical power plants, respectively. Requirements for SO_2 in Sections 306.1 - 306.4 only apply to equipment burning oil, and are therefore not applicable to the proposed AVEF I and II. The applicable NO_x requirement at Rule 320, Section 308.1 for gaseous fossil fuel is 0.2 lb/mmBtu (3-hour average, as NO_2). The AVEF I and II permit limit for NO_x is 3 ppmv for a 3-hour average, and is well below the Rule 320 limitation.

5. Maricopa County Rule 360 and 40 CFR Part 60 – *New Source Performance Standards (NSPS)*

   Federal authority for NSPS requirements (delineated in 40 CFR Part 60) has been delegated to Maricopa County; therefore Rule 360 is the effective NSPS regulation. NSPS applicability is discussed in the previous Section XII.B.

6. 40 CFR Part 68 and Federal Clean Air Act Section 112(r)(1) -- *Accidental Releases of Toxic Chemicals*

   Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Applicability is determined by comparing the amount of a listed substance on-site at a facility to its threshold quantity. AVEF I and II has proposed using 20 to 25 percent aqueous ammonia associated with the SCR NO_x control system. This could trigger risk management planning if more than 20,000 pounds will be stored on-site. In such a case, the Permit requires submittal of a Risk Management Plan as required by 40 CFR Part 68. However, if AVEF I and II uses less than 20% aqueous solution, no Risk Management Plan will be required since less than 20% aqueous ammonia is inherently safer with respect to accidental releases and is exempt from 40 CFR Part 68.

   Regardless of the requirement for a Risk Management Plan, under Section 112(r)(1) of the Federal Clean Air Act, AVEF I and II has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

XIII. TITLE IV APPLICABILITY

AVEF I and II are subject to the acid rain provisions of the Clean Air Act. The permitted emission limits, monitoring, recordkeeping, reporting and other requirements of the Permit include the acid rain provisions of 40 CFR Parts 72, 73 and 75 that apply to AVEF I and II. The proposed Permit serves as a combined PSD, Title V, and Title IV acid rain permit. The AVEF I and II Acid Rain Permit application is incorporated by reference into the proposed Permit.

AVEF I and II hold no SO_2 allocations since they are new units, however, AVEF I and II will have to obtain sufficient SO_2 emission allowances as of the allowance transfer deadline not less than the previous year's actual SO_2 emissions as required by the Acid Rain Program. Since the Acid Rain Program NO_x emissions limits apply only to coal-fired units, there are no Acid Rain Program NO_x limits for AVEF I and II (40 CFR 76.1).

XIV. MONITORING AND COMPLIANCE DEMONSTRATION PROCEDURES

AVEF I and II will install SCR on each of the Combined Cycle Systems to control NO_x emissions and AVEF II will install a CAT-OX to remove CO, VOCs, and HAPs. As part of the Acid Rain Program requirements, continuous emissions monitors (CEMS) for NO_x are required, and the CEMS will meet the requirements in 40 CFR Part 75.

In order to demonstrate compliance with emission limitations for other pollutants, additional monitoring requirements are specified in the permit. In addition to the NO_x CEMS, CEMS for CO (as well as an O_2 diluent gas monitor) will be required on each Combined Cycle System. Natural gas fuel flow meters are also required as part of the Acid Rain Program and will be installed on each fuel line to monitor the unit-specific fuel flow to the combustion turbines and duct burners. These monitors will be installed, certified, and operated in accordance with applicable provisions of 40 CFR Parts 60 (Appendices B and F) and 40 CFR Part 75. For VOC (including HAPs) and PM_{10}, monitored fuel usage in conjunction with emission factors contained in the Permit Application (unless more representative rates can be demonstrated to the Control Officer) will be used to determine emissions. PM_{10} emissions from the cooling towers will be calculated using the total dissolved solids (TDS) concentration in the cooling water as determined through monthly testing.

PM_{10} compliance monitoring will also include a provision to perform a visible emissions observation of the stack emissions from each emission unit each week of operation during which that equipment was used more than 10 hours. If emissions are visible, the AVEF I and II shall obtain an opacity reading conducted in accordance with EPA Reference Method 9 by certified reader within 3 operating days (unless the visible emissions are remedied prior to the 3 days). If opacity exceeds 15% the Control Officer may require emissions testing by other EPA approved Reference Method such as Reference Method 5 to demonstrate compliance with the particulate matter emission limits of these Permit Conditions.

SO_2 emissions will be determined using the sulfur content in the fuel and fuel usage data. Sulfur content of the fuel will be determined through fuel sulfur content testing according to a "custom" fuel testing schedule that is approved as part of the permit.

As provided in Maricopa County Rule 270, performance testing will be required for NO_x, CO, VOC, HAPs, and PM_{10} to demonstrate compliance. Testing will be performed at full load and at reduced load conditions. Initial testing will also be performed for ammonia at full load. Testing is performed annually for $PM_{10,}$ VOC and HAPs, and every five years for NO_x and CO. However, a RATA is required annually for the NO_x and CO monitors. Ammonia testing is required initially and at least every five years unless the ammonia trigger rate is exceeded, in which case testing is required within 3 months of the exceedance.

XV. CONCLUSION AND PROPOSED ACTION

Based on the information supplied by Duke, and on the analyses conducted by the Maricopa County Environmental Services Department, MCESD has determined that the Arlington Valley Energy Facility I and II will employ BACT and for AVEF II in some cases more stringent locally enforceable emissions limits, will not cause or contribute to a violation of any federal ambient air quality standard, will not cause any applicable PSD increment to be exceeded, will not cause any AAAQG to be exceeded, and will not cause additional adverse air quality impacts.

Therefore, MCESD issued to Duke Energy Arlington Valley, LLC an Air Quality Permit for the AVEF I and proposes to issue the Significant Permit Revision for adding AVEF II. The Air Quality Permit, including the significant permit revision, serves as an Authority to Construct and operate the facility, subject to the attached permit conditions.